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MANAGING OIL AND GAS RESOURCES IN AN ERA OF PRICE INSTABILITY

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U.S. Department of the Interior
Office of Policy Analysis
Washington, D.C. 20240

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MANAGING OIL AND GAS RESOURCES IN AN ERA OF PRICE INSTABILITY

Prepared by:

Office of Policy Analysis
U.S. Department of the Interior
Washington, D.C. 20240

April 1, 1988

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INTRODUCTION

To carry out its responsibility for management of oil and gas resources on Federal lands, the U.S. Department of the Interior (DOI) must ensure that oil and gas exploration and production on Federal lands proceed in a timely manner. To ensure orderly and timely development of Federal oil and gas resources, DOI must identify problems that may lead to an inefficient use of these resources and recognize patterns of development that do not serve the long-term interests of the nation. Because Federal lands contain a large share of the nation's inferred (unproven) reserves and undiscovered resources, the pace of exploration on Federal lands will largely determine the future of the nation's oil reserve position. It is particularly important, therefore, that DOI ensure that the pace of oil exploration is consistent with the national interest.

With the drop in world crude prices that occurred in 1986, conditions in the domestic oil industry have changed sufficiently to warrant concern that the current pace of oil exploration may not be in the nation's long-term interest. At the start of 1987 the economic conditions facing the U.S. oil industry make it difficult for U.S. producers to increase domestic production or domestic reserves. This unfavorable economic climate is created largely by three factors:

- Due to geological factors, the cost of producing crude oil from existing reserves and the cost of finding new reserves are much higher in the U.S. than in the Mideast oil producing nations. As the U.S. has depleted its natural endowment of oil resources, other countries have gained a competitive advantage in world crude markets.

- Since 1973 the OPEC nations have manipulated world crude oil prices, creating a source of price instability that would not occur in a competitive market. Oil prices are volatile and unpredictable.

- In January 1986 the acquisition cost of imported crude oil began to fall sharply, reaching $10.91 per barrel in July 1986. Domestic oil prices remain low relative to 1980-1985 levels.

Under these conditions domestic exploration activity has declined. Exploration activity has fallen sharply because the drop in oil prices has made investments in oil exploration less attractive and has reduced the cash flow of the oil industry -- the primary source of capital for exploration. The industry appears to be depleting its existing reserves and not replacing them. Current prices and price expectations may be inadequate to sustain domestic production of 8 to 9 million barrels per day -- a production level the nation has maintained since 1966.

From the standpoint of public policy, there are several reasons to be concerned about these recent developments in the oil industry. The experience of the 1970s shows that oil price increases can contribute to higher inflation, lower productivity growth, and recession. Unfortunately, the decline in oil exploration may lead to market conditions that facilitate such price increases and may worsen their effects on the U.S. economy. If our reserve base decreases, the nation's ability to substitute domestic oil for imported oil in a period of high prices is diminished.

If import dependence is measured by our ability to displace imports when the price increases, recent trends suggest an increase in import dependence. If oil prices rise sharply in the future, a time lag of several years may be involved in an effort to substitute domestic oil for imported oil. Because oil exploration requires skilled manpower with expertise in petroleum geology, reservoir engineering, and drilling rig operation, a time lag is involved in education and training. A time lag also occurs between the start of new exploration activity and the discovery of reserves. Finally, a time lag occurs between a new-field discovery and the achievement of peak production. If any of these these time lags are lengthened as a result of the recent decline in exploration activity, the nation's ability to react to oil price increases is diminished.

FOCUS OF THIS REPORT

To guide resource management policy in an era of oil price instability, the Policy Analysis Office of DOI conducted a review of the factors affecting oil prices; the effects of oil price fluctuations and oil import dependence on the U.S. economy; and alternative philosophical approaches to the definition of the Federal government's role in managing domestic oil exploration activity. The review was focused on four questions:

- What is the outlook for oil prices over the next fifteen years? Are oil prices predictable?
- What are the effects of oil price instability on the U.S. economy?
- What rationales exist, if any, for Federal policy initiatives regarding the domestic oil market?
- What policy options should be considered by the government to address the problem of oil price instability and other problems with the market for oil exploration?

The primary objective of this review is to ensure that Federal policies protect the economic welfare of the nation. The effect of oil supply on national security (in particular, the effect of supply disruptions) was not addressed in this study.[1] The authority for this review stems from DOI's responsibility for managing oil and gas resources.

This report describes an analysis centered on the four questions above. The analysis included the following steps:

1. Identification of problems associated with oil price instability. In this step the basis for government concern about oil price instability was examined. (See Chapter 1.)

2. Identification of possible rationales for policy initiatives. In this step the logical arguments for government intervention in the domestic oil market were examined in relation to economic stabilization and market efficiency objectives. (See Chapter 2.)

3. Identification of general philosophical approaches to Federal policy toward oil markets. In this step different options were identified, based on different sets of premises about the proper role of government in our society. (See Chapter 2.)

4. Identification of specific policy instruments. In this step the various policy instruments available to the Federal government were identified and

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[1] For a review of security concerns, see U.S. Department of Energy, Energy Security: A Report to the President of the United States (Washington, D.C., March 1987), pp. 212-240.

categorized, for each general philosophical approach. (See Chapters 3, 4, and 5.)

5. Analysis of cost-effectiveness of policy instruments. In this step the likely effects of policy instruments were evaluated against policy objectives. (See Chapters 3, 4, and 5.)

The findings of this study are summarized below.

FINDINGS REGARDING OIL PRICE INSTABILITY

Although in the early 1980s many analysts expected oil prices to increase steadily, it now appears that the world oil market will go through boom and bust cycles for many years. Large fluctuations in oil prices are likely to occur even in the absence of supply disruptions. This change in expectations has important implications for Federal energy leasing programs and other energy policy decisions.

The current slump in domestic oil exploration and development is only one of the detrimental effects on the U.S. economy of boom and bust cycles in the world oil market. Some of the adverse economic effects of a cyclical oil price pattern are worsened when oil imports represent a large share of U.S. petroleum product consumption.

The global oil industry can be expected to go through boom and bust cycles, as oil prices fluctuate between a floor price around $8 per barrel and the ceiling price of perhaps $50 per barrel.

- From January 1979 through July 1986, the average price of crude oil purchased by U.S. refiners followed a boom and bust pattern.
- The cycle of boom and bust may be repeated. Oil market conditions are conducive to rapid price increases and rapid price decreases.
- Major changes in oil prices can occur without supply disruptions.

Oil price instability is not a "special interest" issue affecting a small sector of the U.S. economy; it affects the whole economy.

- As oil prices rise and fall, U.S. expenditures on energy and energy conservation will rise and fall.

- The magnitude of fluctuations in energy expenditure is large in relation to GNP. The macroeconomic effects of oil price changes are therefore large.

- Oil price instability causes shocks to the global economy, not just the U.S. economy.

The Federal government should be concerned about the boom and bust cycle of world oil prices because this cycle adversely affects the U.S. economy in several ways. The fact that oil prices today are low in relation to 1979-1985 prices should not be considered an indication that our energy concerns are over.

- Inflation is increased by a cyclical pattern of oil prices.

- Unemployment may be increased by a cyclical pattern of oil prices.

- Labor productivity is reduced by a cyclical pattern of oil prices.

- The security of U.S. financial institutions is reduced by a cyclical pattern of oil prices.

- The international competitiveness of U.S. industry is affected by currency fluctuations. Cyclical oil prices increase the business risk associated with currency fluctuations.

- When oil prices are unstable and unpredictable, there is a greater risk that we will consume our remaining domestic oil resources when we do not need them the most -- that we will consume them too soon or too late.

- Currently Federal energy policy does not attempt to dampen the boom and bust cycle in the energy industry. In many ways it may exacerbate it.

- The Federal government is already committed to absorbing a portion of the economic losses associated with the cyclical nature of the oil industry.

Oil import dependence may be defined as the inability of a nation to reduce oil imports to a small share of total energy consumption even during a period of high oil prices (e.g., prices above $30 per barrel). Although the economy will be affected by oil prices regardless of the level of imports, there are several reasons to be concerned about the effect of oil import dependence on the nation's economic health.

- Because the world oil market is not workably competitive, dependence on oil imports create the potential for an excessive transfer of income or wealth to oil-exporting nations.
- Because oil prices are volatile and unpredictable, private firms may not pursue investments that can displace oil imports over the long term and be cost-effective for the nation as a whole.
- In an era of cyclical oil prices, increased dependence on oil imports is likely to increase inflationary pressures on the U.S. economy.
- In an era of cyclical oil prices, increased dependence on oil imports increases the business risk associated with trade imbalances and currency fluctuations.

FINDINGS REGARDING RATIONALES FOR POLICY INITIATIVES

There exist both economic stability and market efficiency rationales for policy initiatives designed to mitigate the effects of oil price instability. Two economic stability issues can be cited to support Federal intervention in oil markets:

- Economic stability benefits associated with reduced dependence on imports are achieved by policies that increase the ability of the domestic oil industry to increase production when oil prices "peak." These policy options would enable domestic resources to displace oil imports when necessary, and would yield the benefits associated with reduced dependence on oil imports, and yet postpone domestic production to the times when it is most needed. These policy options may be regarded as a complement to the Strategic Petroleum Reserve, which permits a short-term "peak" in domestic crude oil receipts at refineries.
- Economic stability benefits associated with reducing the adjustment costs associated with oil price swings are achieved by policy options that dampen the "boom and bust" cycle of domestic oil exploration. The benefits of these policy options would be reduced unemployment, increased labor productivity, increased security of financial institutions, and an increase in the ability

of the domestic oil industry to raise production when oil prices "peak."

Several market efficiency issues may be used to define rationales for policy initiatives:

- Unnecessary statutory and regulatory impediments to domestic oil and gas exploration may prevent resources from being allocated to oil exploration, and may prevent an efficient pattern of development.
- Exploration in frontier areas is a "merit good." The benefits of a new discovery in a frontier area include information that will help other firms find oil; information that will help identify the size of the domestic resource base; and information that will decrease in the lead time needed to bring frontier resources into production in response to a price increase.
- The threat of a crash in oil prices may create a capital market imperfection that restricts exploration.
- Under today's price expectations, Federal expenditures for energy development may be imbalanced. Frontier exploration is analogous to long-term, high-risk energy research and development (R&D). That is, both have high risk/return ratios because of the divergence between private and social benefits.

All of these rationales are reflected in the policy options examined in this study.

FINDINGS REGARDING POLICY OPTIONS

There are three levels of policy response the government could take:

Level 1: Remove unnecessary impediments to oil and gas exploration.

Level 2: Remove unnecessary impediments to oil and gas exploration and support exploration in frontier areas.

Level 3: Remove unnecessary impediments to oil and gas exploration, support exploration in frontier areas, and dampen cyclical fluctuations in domestic oil exploration activity.

A choice among these options is in part dependent on political philosophies.

Removal of unnecessary impediments to exploration may encourage reserve creation through additional exploration and more complete recovery of existing "marginal" reserves. Specific measures that are recommended for consideration include:

- Providing improved access to certain oil and gas exploration areas that may contain significant undiscovered recoverable resources. Areas for which improved access may be desirable include the California OCS and the Alaska National Wildlife Refuge.
- Repeal of oil and gas production diligence requirements for Federal leases. If some firms hold strong expectations about possible future increases in oil prices, this measure would permit those firms to explore and hold undeveloped reserves in the expectation of higher oil prices without violating production diligence requirements.
- Implementing a sliding scale royalty for Federal oil and gas leases that would scale from the currently applicable rate (typically one-eighth for onshore production and one-sixth for offshore) to zero on low production rate wells. The aim of this measure would be to encourage more thorough recovery from economically marginal reserves.
- Reducing the minimum bid on Outer Continental Shelf leases from the current value of $150 per acre to the pre-1983 value of $25 per acre.
- Lifting the ban on export of crude oil from Alaska.

Promotion of exploration in frontier areas would improve the nation's ability to increase oil production in response to oil price increases. In the recognition that future oil price increases might lead to a relatively rapid conversion of indicated and inferred reserves to proven reserves, efforts to provide longer term benefits from the stimulation of new exploration/reserve creation probably should aim at so-called undiscovered economically recoverable resources--those resources that are contained in undeveloped and frequently unexplored areas. Moreover, because the greater probability of finding significant, new petroleum reserves may lie in higher-risk, frontier areas, emphasis might be given to such areas in efforts to stimulate exploration activity. Exploration in such areas will also contribute valuable information on resource potential that is vital to the formulation of coherent longer-term national energy policy.

To be cost-effective a Federal policy to promote oil exploration must tie receipt of economic incentives to completion of exploration or reserve creation activity. Incentives aimed at cash flow enhancement alone are not likely to be a cost-effective method of promoting exploration. At today's oil prices, major oil firms may use only a fraction (perhaps one-sixth) of their cash flow from operations to support exploration activity.

In general, the measures that were found to be most effective in promoting additional exploration/reserve creation activity are those that reduce the effective cost of exploration. Compared to measures that would reduce development/production costs or increase production prices, measures that reduce exploration cost do not expose the exploring firm to the risk of resource discovery in order to benefit from the measure. That is, the cash-flow benefits of measures to reduce exploration cost are immediate, thus directly improving the ability of firms to finance and undertake additional exploration activity. Moreover, the goal of reducing import dependence implies a desire to encourage exploration, not production. Measures that are recommended for further consideration include:

- Exploration cost credits against Federal lease payments (i.e., royalties, rentals and bonuses on offshore and onshore Federal oil and gas leases). An example of such an incentive would be a competitive auction in which the Federal government offered to provide the winning bidder on each tract with a specific sum of money, conditioned upon the completion of an exploratory well on that tract. Under this system the government would, in effect, lower the minimum bid on a frontier tract to a negative value, subject to the condition that the tract be explored. The exploration credit could be funded by lease revenue from existing tracts.

- Exploration cost credits from an "Exploration Trust" funded by a petroleum product consumption/excise tax (e.g., a gasoline tax). In a similar concept to the funding of the Federal Highway Trust Fund from motor fuel taxes, an oil consumption/excise tax could be used to fund a Federal Exploration Trust. Exploring firms would subsequently receive fractional rebates of their qualifying exploration outlays from the trust. The oil consumption tax would be applied to both imports and domestic production and would raise the apparent price of oil to consumers. The fund would be administered as an off-budget, self-financing program.

o Exploration cost credits against a floating excise tax applied in conjunction with a large, fixed oil import fee. This package of measures includes: an oil import fee; a floating excise tax assessed on the lesser of the amount of the fee or the difference between domestic oil prices after implementation of the fee and an inflation-adjusted benchmark price; and an option for firms to credit a fraction of qualifying exploration costs against their excise tax liability. To dampen partially the effect of the oil price rise on consumers, the import fee revenues might be rebated through the general income tax.

All of these measures are aimed at promoting reserve creation by reducing the effective cost of exploration to the exploring firm. In addition, the measures provide financial support for expanded exploration activity. However, by tying receipt of the financial support to the undertaking of exploration activity, these measures should be more effective than simple "cash-support" measures (e.g., a reduction in Federal royalty payments) in promoting additional exploration.

The exploration cost crediting component of these measures may be varied depending on the location and character of the qualifying exploration/reserve creation activity -- that is, expenditures for new field wildcat drilling in higher risk frontier areas could receive a larger credit than exploration outlays in more mature, lower risk areas. Varying the value of the credit in this way would increase the effectiveness of the incentive in encouraging exploration in those areas with greater potential for significant new discoveries and greater value in providing information for policy-making. In addition, by encouraging firms to explore in these higher risk, frontier areas that they would now otherwise likely ignore, there is a greater likelihood that the exploration incentive will apply to new, incremental activity instead of exploration that would have been undertaken in any event.

To dampen cyclical fluctuations in exploration activity the Federal government could provide support to exploration activity during periods of low oil prices. The policy instruments that could be used to raise exploration activity between oil price peaks are very similar to the instruments that could be used to promote exploration in frontier areas. First, there is a set of initiatives that could be funded by Federal lease revenue:

- Adjustable exploration/reserve creation credits against Federal lease payments. The percentage credit may vary over time, or the definition of qualifying wells may vary over time.

- Adjustments in the royalty rate on frontier areas. The rate may be higher in "peak" periods than in "trough" periods.

Second, there is a set of initiatives that could be funded by excise taxes that vary over time:

- Exploration/reserve creation credits against a floating excise tax applied in conjunction with a variable oil import fee. The oil import fee could vary inversely with world oil prices.

- Exploration/reserve creation credits from a trust funded by an oil consumption tax. The excise tax rate could vary over time, falling to zero during periods of high prices.

Although these initiatives would expand the scope of the program well beyond the traditional responsibilities of the Department of the Interior, they may be necessary to:

- Stabilize the level of oil exploration activity on state and private lands

- Increase the dollar amount of the funding base used to support exploration during a period of low oil prices

- Ease or remove the impact of the program on the Federal deficit.

In short, the development of a policy to dampen the boom and bust cycle of domestic oil exploration should not require any additional administrative mechanism, given a policy of promoting exploration in frontier areas.

SCOPE OF THIS REPORT

This report begins, in Chapter 1, with a discussion of the causes of oil price instability and the effects of this instability on the U.S. economy. In Chapter 2 the possible rationales for Federal policy initiatives regarding the oil industry are identified and linked with the three levels of policy response listed above. Chapter 3 identifies the policy initiatives that could remove impediments to oil exploration. Chapter 4 describes policy instruments that can be used to promote exploration in frontier areas. Finally, Chapter 5 presents a discussion of ways the Federal government might dampen the boom and bust cycles in domestic oil exploration.

CHAPTER 1

CRUDE OIL PRICE MOVEMENTS AND THE U.S. ECONOMY

The oil price crash of 1986 led to sharp cutbacks in domestic oil exploration. If the Federal government could confidently predict that world crude oil prices will remain in a $15 to $18 per barrel range (in constant dollars), the cut in exploration could be regarded as an appropriate, acceptable response of the marketplace to a new price level. Under these circumstances it would be difficult to develop an economic argument that there is a "problem" with the marketplace and that some sort of Federal government intervention is needed to address the problem.

Unfortunately there is no evidence of stability in oil prices. On the contrary, there is evidence that the natural tendency of the crude oil market is to move through boom and bust phases.

The purpose of this chapter is to identify the adverse effects on the U.S. economy of instability in world oil prices. The chapter is intended to address the question whether there is a fundamental "problem" with the domestic oil market that prevents it from responding efficiently to world oil price changes. The general conclusions are:

1. The global oil industry can be expected to go through boom and bust cycles, as oil prices fluctuate between a competitive floor and a ceiling.

2. Oil price instability is not a "special interest" issue affecting a small sector of the U.S. economy; it affects the whole economy.

3. The boom and bust cycle of world oil prices adversely affects the U.S. economy and has significant effects on inflation, unemployment, labor productivity, and the stability of financial institutions.

4. Although the economy will be affected by oil prices regardless of the level of imports, there are several reasons to be concerned about the effect of

oil import dependence on the nation's economic health. Dependence on oil imports is likely to increase inflationary pressures on the U.S. economy and increase the business risk associated with trade imbalances and currency fluctuations.

The chapter does not attempt to determine whether new Federal policy initiatives should be undertaken to address these problems.

This chapter is organized in four sections:

- **The Outlook for Oil Prices Over the Next Fifteen Years.** This section reviews the recent history of oil prices and shows why oil prices can be expected to fluctuate between a floor and a ceiling.
- **The Magnitude of the Effects of Oil Prices on the Economy.** This section explains why swings in oil prices have a large effect on the U.S. economy, rather than a small effect.
- **Economic Problems Created By an Unstable Pattern of Oil Prices.** This section details the reasons why instability in oil prices should be a concern, regardless of the level of import dependence.
- **Economic Problems Created by Dependence on Oil Imports.** This section lists the reasons why dependence on oil imports should be a policy concern, given the likelihood of oil price instability.

THE OUTLOOK FOR OIL PRICES OVER THE NEXT FIFTEEN YEARS

The global oil industry can be expected to go through boom and bust cycles, as oil prices fluctuate between a competitive floor and a ceiling. The floor price may be around $8 per barrel (even lower than the July 1986 monthly average) and the ceiling price may be around $50 per barrel (the highest monthly average of the last decade, expressed in today's dollars).

This section begins with a discussion of the factors affecting oil prices since 1979. The reasons why oil prices are likely to be cyclical are identified. Finally, some remarks on the effects of oil supply disruptions are added.

From January 1979 through July 1986, the average price of crude oil purchased by U.S. refiners followed a boom and bust pattern.

In January 1979 the average price of oil imported by the United States began to increase from a 1975-1978 level of around $14 per barrel, in current dollars (see Exhibit 1.a).[1] Prices continued to rise through January 1981, and reached the equivalent of about $49 per barrel, in today's dollars (see Exhibit 1.b). This price level, together with fears that prices would remain at a high level or go still higher, led to decreases in global oil demand and increases in non-OPEC supply that led to a sharp decline in oil prices in 1986.

The sharp rise in prices in 1979-1981 led to a variety of energy conservation and oil conservation efforts aimed at reducing energy-related costs and oil imports. Some of these efforts in the U.S. included legislation such as the Fuel Use Act (which prohibited the construction of oil-fired power plants), industrial fuel switching (e.g., from oil to coal), and production of smaller and more fuel-efficient automobiles. High oil prices promoted alternative energy sources and conservation programs. Solar, renewable, and gasohol alternatives emerged, while home insulation tax credits, EPA-mandated mileage standards, and a 55 mph speed limit cut into demand. The sharp rise in energy prices also inhibited economic growth, further curtailing oil demand.

The oil price increase of 1979-1981 also created an economic incentive to find and develop new domestic oil fields. Higher non-OPEC oil production is a direct consequence of higher oil prices and the desire for enhanced national energy security.

From 1982 through 1985, OPEC lowered production and prices in an attempt to stabilize a deteriorating supply/demand balance. OPEC members that had planned for year after year of climbing oil demand, prices, and export revenues were shocked. For Saudi Arabia, oil revenues declined by roughly 80 percent between 1980 and 1985. And as prices and export revenues fell, OPEC members saw their debts rise and their current account balances decline.

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[1] Monthly changes in world oil prices can be measured by changes in the monthly average U.S. refiner acquisition cost of imported crude oil. While the average refiner acquisition cost does not reflect an adjustment for changes over time in the mix of crudes purchased by the U.S., it is a good indicator of the cost of imported oil because it reflects actual prices paid (not just posted prices) and it does not give undue weight to the pricing policies of any single country.

Exhibit 1.a

Refiner Acquisition Cost - Imported Oil

In current dollars

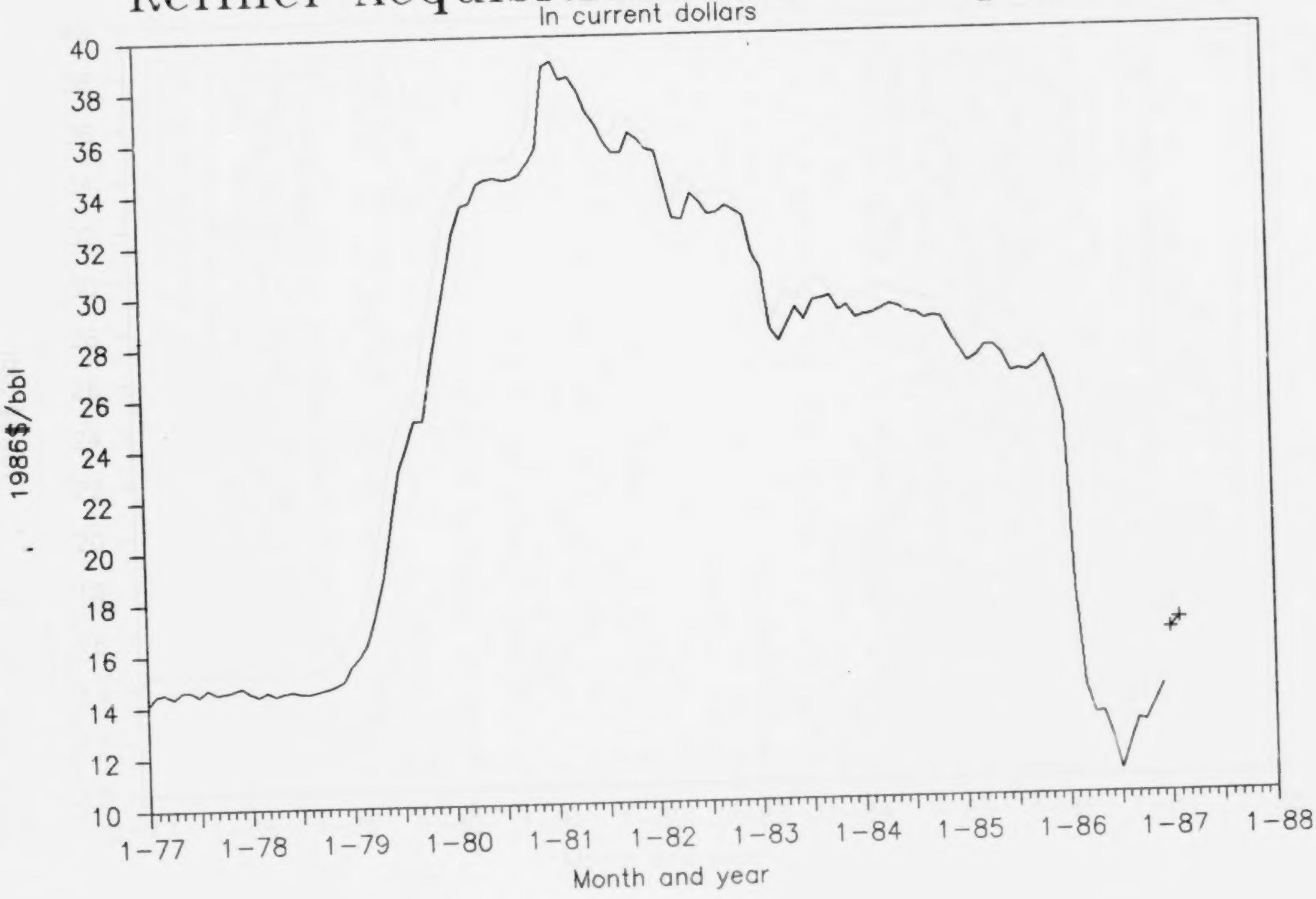
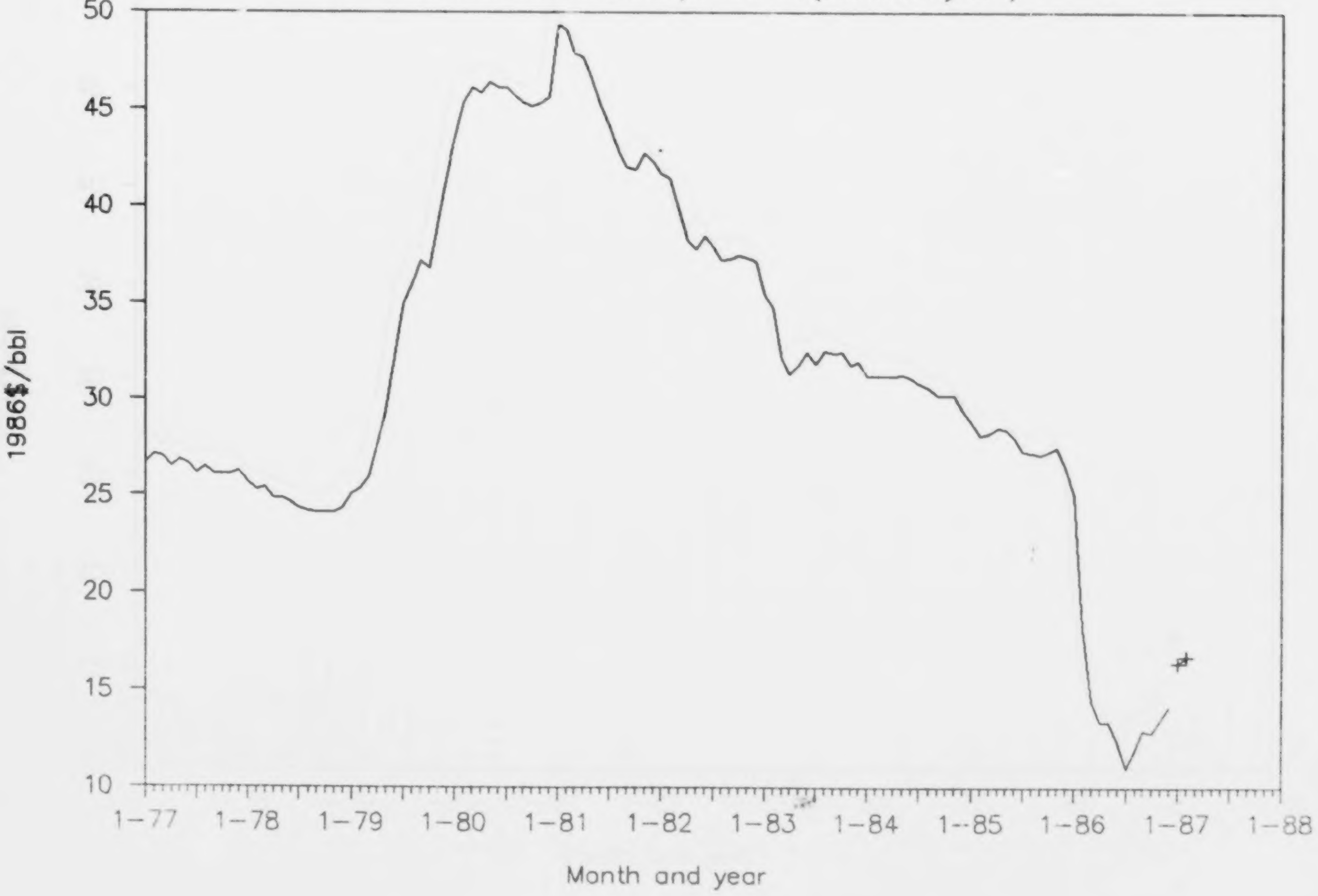


Exhibit 1.b

Refiner Acquisition Cost – Imported Oil

December 1986 dollars per barrel (deflated by CPI)



OPEC's attempts to stabilize prices by setting lower and lower production quotas failed as some OPEC members, heavily burdened by debt and in need of dollars, produced in excess of their quotas. Large, price-induced commercial inventory drawdowns also contributed to the worsening supply/demand imbalance (generally, commercial inventories rise with rising prices and fall with falling prices). In order to move these extra supplies into the marketplace as surreptitiously as possible, a variety of hidden price discounting mechanisms were established to undercut official prices. Saudi Arabia undertook the role of the cartel's "swing producer," lowering production to keep total OPEC production under quota, thus helping to prop prices.

By late 1985, Saudi Arabia had grown tired of the consistent cheating by fellow OPEC members. Official prices had fallen to $27 per barrel, with much crude available on the spot market for $2 to $4 less. Saudi production had fallen to nearly 3 million barrels per day from highs of roughly 10 million barrels per day. Saudi Arabia abandoned its role as the swing producer in OPEC, initiating a netback pricing policy that led to a sharp rise in OPEC oil output and a consequent plunge in oil prices.

The oil boom of 1979-1982 was driven by price expectations as well as actual supply and demand conditions. Many investments in energy conservation, non-petroleum energy and non-OPEC oil production were premised on prices above $40 per barrel (in today's dollars). Oil producers' expectations tended to be optimistic, from 1979 through 1985.[2] Even in late 1985, when the Saudi production level was so low that the need for some sort of correction was widely recognized, most analysts failed to anticipate the magnitude of the 1986 drop in prices.

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[2] Oil price expectations over the 1965-1985 period are described in Arthur Anderson & Co. and Cambridge Energy Research Associates, The Future of Oil Prices: The Perils of Prophecy, cited in testimony of Dr. Daniel Yergin before the U.S. House of Representatives, Committee on Energy & Commerce, Subcommittee on Fossil and Synthetic Fuels, March 6, 1986. In Vintage 4 (the growth phase of the 1979-1985 boom) and Vintage 5 (the decline phase of the 1979-1985 boom) projections the price crash of 1986 was not anticipated.

The cycle of boom and bust may be repeated. Oil market conditions are conducive to rapid price increases and rapid price decreases.

Many, if not all, oil industry analysts believe that oil prices will continue to be highly volatile. The following statements are illustrative:

> M.A. Adelman: "We see again the basic instability of the cartel: higher prices permit the accumulation of assets, strengthening the drive toward even higher prices. Lower prices generate forces making for even lower prices. ...The cartel's problems, which will never go away, do not promise any period of stable prices, at any level."[3]
>
> "... Most likely, the price will fluctuate between the monopoly ceiling and the competitive floor."[4]
>
> Arlon Tussing: "Even if the long-term equilibrium price of oil is, in principle, somewhere around the middle teens, history tells us not to expect actual prices to stay there very long. Rather, they can be expected to swing at intervals of widely differing length well above and below their long-term path."[5]
>
> Edward W. Erickson: "Following the integration of the Middle East oil resources into the world supply and demand network, the behavior of world oil prices has been one of punctuated equilibria. Stress builds up and creates a necessity for change, which is relieved by discrete events. Movements in nominal prices have been sharp and large. ...After each discrete and discontinuous change in the reference price, the Saudis appear to

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[3] M.A. Adelman, "An Unstable World Oil Market," The Energy Journal 6,1 (January 1985), p. 21.

[4] M.A. Adelman, "The Competitive Floor to World Oil Prices," The Energy Journal 7,4 (October 1986), p. 29.

[5] Testimony of Arlon Tussing before the U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Fossil and Synthetic Fuels, March 6, 1986, p. 2.

> use their toleration of wide output swings to discipline the market."[6]
>
> Philip K. Verleger, Jr.: "... oil has evolved into an economic commodity. This evolution makes the prediction of future prices very difficult. ... Oil prices could easily oscillate over a very wide range in the next decade."[7]
>
> The Staff of the International Monetary Fund: "As the world will be faced with considerable unused production capacity for several years, the price of oil could fluctuate within a very wide range."[8]

The primary sources of oil price volatility are the changing behavior of OPEC members and the long lead time necessary to bring non-OPEC supply (or global oil demand) in line with price expectations.[9] The first factor is not found in competitive markets, while the second factor is a normal market phenomenon in agriculture, metals, and other commodity markets with long production lead times.

Although oil prices fell sharply in 1986, the members of OPEC continue to exert a powerful influence on oil prices. This point is demonstrated by a recent study of the global long-run marginal cost of oil. If OPEC were to permanently collapse and if all nations acted competitively the price of oil would fall to $5 per barrel and remain there for a decade:

> At the low-cost end (assuming competition and completely independent decisionmaking) a price of over $5 would make it profitable for the OPEC nations to expand their output to over 60 million

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[6] By "discrete events" Erickson appears to refer to discrete changes in Saudi policy, not supply disruptions. Edward W. Erickson, "Prospects for a Tighter World Oil Market," The Energy Journal 6,1 (January 1985), pp. 4-5.

[7] Testimony of Philip K. Verleger before the U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Fossil Fuels, July 11, 1985, p. 1.

[8] International Monetary Fund, World Economic Outlook: April 1986 (Washington, D.C.: IMF, 1986), p. 160.

[9] For a discussion of the sources of oil price volatility see Appendix A.

> barrels daily. That price would be sustainable past 1995 at the least.[10]

The price floor that could be reached by a temporary collapse of OPEC is estimated to be approximately $8 per barrel, because prices below this level will trigger large cutbacks in U.S. production.[11] The ceiling price must be defined in terms of the time period over which the price is sustained. The ceiling on daily or weekly average oil prices is determined primarily by OPEC's ability to enforce strict production cutbacks, while the ceiling on the annual average price is determined by OPEC's production cutbacks plus the elasticities of world demand and of non-OPEC supply.[12] A simple, rough measure of the monthly ceiling price is the highest historical monthly average refiner acquisition cost of imported oil, expressed in 1986 dollars -- just under $50 per barrel (see Exhibit 1.b). This estimate is based on the assumption that the price of oil fell from its January 1981 peak because this price level was not sustainable, and on the simple assumption that this ceiling price (adjusted for inflation) has not moved significantly since 1981.[13]

For a given quarter it is reasonable to consider both global oil demand (excluding inventory accumulation) and non-OPEC supply to be highly inelastic, yielding a highly inelastic demand curve for OPEC oil. Prices rise or fall in a given quarter depending on what OPEC produces relative to the demand for its oil in that quarter. OPEC may overproduce or underproduce, relative to the production level that would achieve a constant oil price level. OPEC's practice of setting quotas makes the short-run supply of OPEC oil inelastic. Prices are volatile because OPEC behavior is unpredictable and because short-run supply and demand are both inelastic.

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[10] M.A. Adelman, "The Competitive Floor to World Oil Prices," p. 10.

[11] Adelman, "The Competitive Floor to World Oil Prices," p. 29. An even lower floor ($2 to $5 per barrel) has been suggested in a study of short-run marginal costs of Texas oil production. See James M. Griffin and Clifton T. Jones, "Falling Oil Prices: Where is the Floor?," The Energy Journal 7,4 (October 1986), p. 49.

[12] The elasticity of world oil demand is the price elasticity of demand -- the percentage change in quantity of oil that purchasers want to purchase, given a 1 percent change in the price of oil. If demand is "highly elastic," the quantity of oil that purchasers want to purchase is very sensitive to prices. If demand is "inelastic," purchasers will want to purchase a certain quantity no matter what the price of oil is. Similarly, the elasticity of non-OPEC supply is the price elasticity of non-OPEC supply -- the percentage change in quantity of oil that non-OPEC producers are willing to produce, given a 1 percent change in the price of oil. If non-OPEC supply is "highly elastic," rising oil prices will lead to rapid growth of non-OPEC production. If non-OPEC supply is "inelastic," rising oil prices will have very little effect on non-OPEC production.

[13] To estimate the current price ceiling and project the celing over the next decade, further research is needed.

The fundamental cause of oil price instability is the fact that OPEC nations, particularly Saudi Arabia, own a substantial fraction of the world's capacity to produce oil at costs less than $8 per barrel. Almost half of the world's oil that remains to be produced is in the Middle East, which holds 53 percent of the world's identified reserves and nearly a quarter of its undiscovered resources. Existing geologic information indicates that there is little likelihood of discoveries anywhere in the world that would significantly alter the geographic distribution of conventional crude oil resources.

The difficulty of predicting oil prices is partially attributable to the fact that OPEC is neither a monopolist-- an organization with the power to keep prices at rent-maximizing levels indefinitely -- nor a powerless organization. At one time or another, prices may be determined by rational economic behavior in markets characterized by competition, oligopoly, or monopoly behavior, or simply by political decisions that are economically "irrational" by Western standards. OPEC's short-term output fluctuations do not fit a simple, predictable model (e.g., the behavior of a competitive firm according to microeconomic theory).

One indicator of market tightness (and therefore of OPEC's ability to restrict supply) is Saudi Arabia's share of OPEC production. When the demand for OPEC oil is strong, Saudi Arabia's share of OPEC production is likely to be large. When the oil market has excess supply, Saudi Arabia's share of OPEC production is likely to be small. Over the long term, a high Saudi share of OPEC capacity is associated with high prices (see Exhibit 1.c). The "fit" of this relationship appears particularly good when 1985 is considered an abnormal year. These data support the hypothesis that Saudi Arabia behaves as a "swing" producer.[14]

Prices rise or fall as the short-run global supply curve is "shifted" to the right or to the left by OPEC. The short-term effect of these shifts in the short-run supply curve is an increase or decrease in global oil inventories. The

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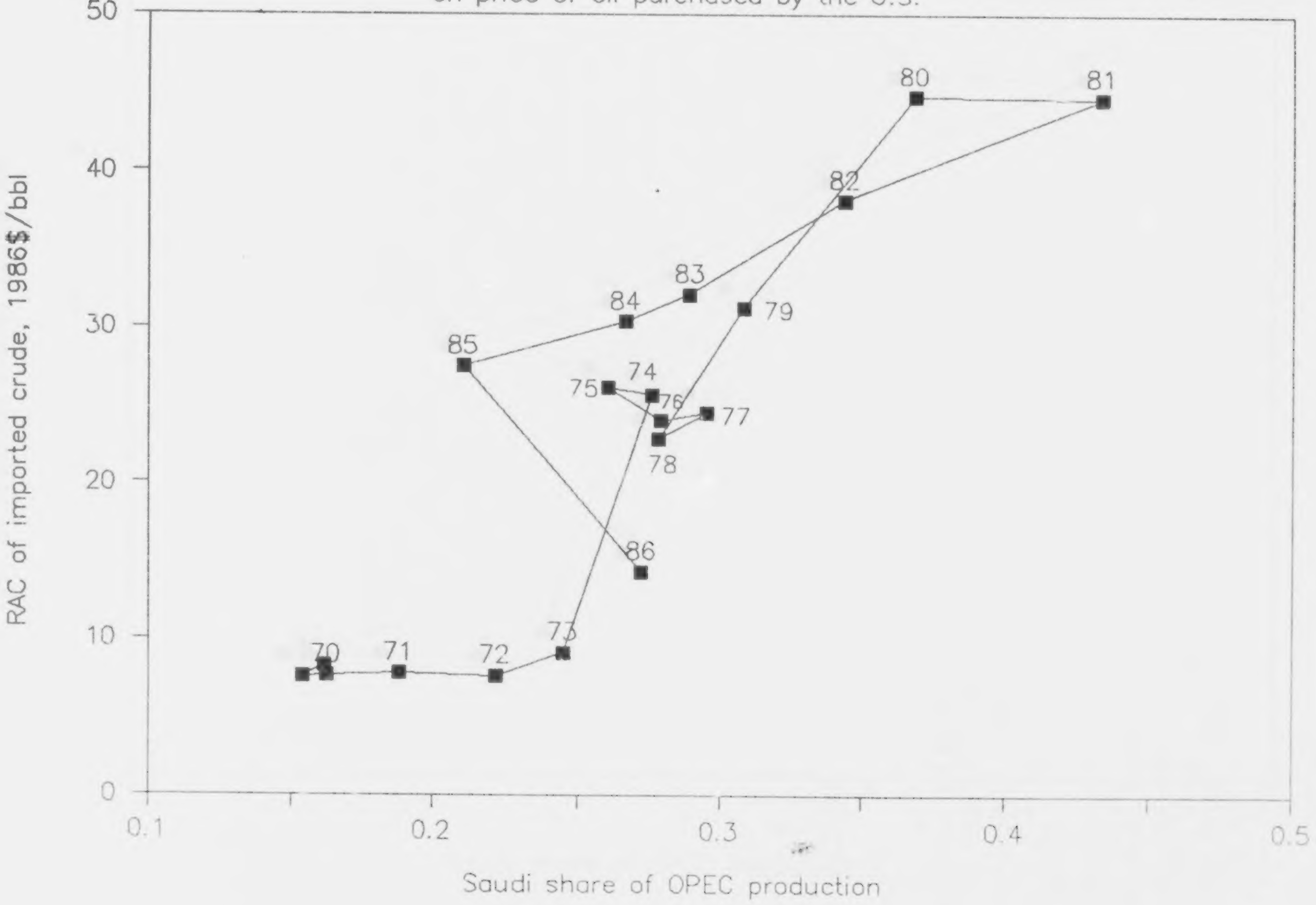
[14] For a discussion of the Saudi role as "swing producer," see American Petroleum Institute, Domestic Petroleum Production and National Security, December 30, 1986, pp. I-8 to I-12.

Exhibit 1.c

Effect of Saudi share of OPEC output

on price of oil purchased by the U.S.



short-run global supply curve is the sum of three components: OPEC supply, which is only as elastic as the practice of "cheating" on OPEC quotas will permit;[15] non-OPEC supply, which is only as elastic as resource conditions and economic structure and policy will permit; and the net decrease in inventories, which is highly sensitive to short-term price expectations.

Short-term oil prices are highly sensitive to output fluctuations that represent only a few percentage points of world oil supply, i.e., fluctuations equivalent to one or two weeks' worth of inventory. The cost of inventory is sufficiently large, and the long-term price trend is sufficiently uncertain, that the oil market responds to inventory changes that might seem small relative to inventory changes in some other commodity markets. In the oil market an "overhang" of 6 days' production (about 300 million barrels) is considered large.

Although real U.S. wellhead oil prices were stable over the 1957-1972 period, a cyclical pattern is apparent in the 1870-1957 period. Peaks occurred in 1870, 1900, 1920, 1937, 1957 and 1981. The magnitude of price fluctuations over this period is much smaller, however, than the magnitude of price fluctuations over the 1973-1986 period.[16]

A cyclical pattern of prices, with boom and bust periods in the history of an industry, is not unique to oil. Many commodities traded in world markets are subject to price volatility. Over the 1960-1986 period the magnitude of oil price fluctuations has been unusually large, however. Precious metals (gold and silver) are the only other commodity group with comparable price fluctuations.[17] The size of the 1972-1981 percentage increase in world oil prices must be explained by the role of OPEC (or its largest reserve holder, Saudi Arabia) rather than "normal" commodity price fluctuations:

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[15] If OPEC behaved as a "perfect" monopolist, its short-run supply curve would be perfectly inelastic.

[16] Richard Gordon, "A Petroleum Policy Overview," prepared for the Minerals Management Service of the Department of the Interior, 1986, pp. 3-4.

[17] For a detailed discussion of this point, see Appendix B.

> The world oil monopoly is both the largest of all time, and is also the greatest in the divergence of price from long-run marginal cost.[18]

The volatility of oil prices has increased since the 1960s. Even if the long-term trend in prices is ignored, and price volatility is measured over a given time period by the ratio of the mean price to the standard deviation, it is clear that the volatility of petroleum product prices has increased in the last 25 years:

> A comparison of data on the fluctuation of prices during the period from 1960 to 1972 and 1979 to 1984 indicates that the volatility in prices has increased substantially.[19]

The volatility of oil prices could increase in the future, as the short-run price elasticities of non-OPEC supply and global demand decline over time. Two trends should be noted:

- With each passing decade the world's resources of low-cost non-OPEC oil become depleted. There is little hope that discoveries of low-cost non-OPEC oil will be large enough to offset this trend. Because the remaining resources cost much more to find and develop, the lead time required to bring 1 million barrels per day of new non-OPEC supply into production will likely increase.

- Barring technological breakthroughs, the lead time required to achieve a 10 percent improvement in energy efficiency will likely increase as the energy efficiency of the global economy rises.

Because the latter effect is offset by investments in capability to displace oil with other fuels, or displace motor vehicle and airline transportation with rail transportation, the elasticity of world oil demand need not decline. The elasticity of non-OPEC supply is likely to decline, however, unless governments take action to offset this trend (e.g., increase oil exploration in frontier areas).

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[18] M.A. Adelman, "The Competitive Floor to World Oil Prices," The Energy Journal 7,4 (October 1986), pp. 29-30.

[19] Testimony of Philip K. Verleger before the U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Fossil Fuels, July 11, 1985, pp. 20-23.

If non-OPEC supply becomes less elastic, a change of 1 million barrels per day in OPEC production will exert a greater effect on oil prices. A smaller OPEC output change would be necessary to achieve a given change in the world oil price level. Under these conditions the boom and bust cycle of oil prices could become more severe, in the long run, in terms of both amplitude and period of the cycle.

The discovery of supergiant fields such as the North Slope of Alaska and the North Sea has tended to restrain oil price increases in the 1970s and 1980s. The decline in oil prices since 1981 has been aided by the growth of North Sea production. When these supergiant non-OPEC fields are depleted, the outlook for non-OPEC supply may not be as bright. If no more supergiant fields are discovered in non-OPEC nations, the effective ceiling on oil prices will probably rise in the future. If only a few more supergiant fields are discovered in non-OPEC nations, the current oil price ceiling may be sustained. If many more supergiant fields are discovered in non-OPEC nations, the oil price ceiling will probably decline.

Major changes in oil prices can occur without supply disruptions.

An oil supply disruption may be defined as a loss of crude oil production or transportation capacity due to "force majeure" conditions (war, revolution, natural disaster, fire, accident, or terrorist attack) or politically motivated embargoes targeted on particular consuming countries. Under this definition, a decision by OPEC or by Saudi Arabia to exercise monopoly power -- to decrease capacity utilization in order to raise prices -- is not a disruption, even if the change in output is announced suddenly.[20]

Supply disruptions are not necessary to create sharp price increases. OPEC actions to restrict OPEC supply can raise prices swiftly in the absence of a disruption. Conversely, a drop in oil prices can occur without a sudden lifting of an embargo, or a sudden restoration of productive capacity following a military or terrorist attack. A sharp price decline can be caused by a Saudi decision to discipline OPEC members who have cheated on their production quotas. It is, therefore, more useful to consider the impacts of "price disruptions," generally.

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[20] If an economically motivated action taken by an oil producer (such as a nationalized oil company in an OPEC nation) is considered a "disruption", the effects of underlying market conditions become confused with the effects of non-market events.

The decline in prices in 1986 was clearly not caused by changes in production capacity or oil demand. Similarly, the sharp reversal that began in July 1986 and caused a 50 percent price increase in 6 months was not a result of a supply disruption. These events are not abnormal; they are likely to be repeated.

When OPEC producers decide to offset production losses from a disruption in one country by raising production elsewhere, the disruption will have a modest, temporary effect on prices. Conversely, when OPEC producers choose not to offset production losses from a disruption, a sharp price increase will occur. In the latter situation the disruption triggers a change in price level that might have occurred within a few months in any event.

A review of events surrounding the price increases of 1979-1980 is complicated by the fact that disruptions (in particular, the revolution in Iran) occurred at the same time market conditions (global demand and non-OPEC supply) facilitated the exercise of OPEC power. The limited importance of disruptions is illustrated, however, by examining the price effect of the outbreak of the war between Iran and Iraq in late September 1980:

> The effect of the war on oil supply was dramatic. Over a sixty-day period free world production dropped by 3.6 million barrels a day from 59.5 to 55.9 million barrels a day -- a cut matched only by the drop in 1973. The effect on prices was, however, less than might have been expected... the war between Iran and Iraq caused a loss of production that was offset by increased production from Saudi Arabia, Kuwait, and other countries.[21]

The effect of this disruption on the cost of U.S. oil imports is illustrated by the 9-month peak section of the curve shown in Exhibit 1.a. While prices jumped in September 1980, the increase was modest relative to the January 1979-February 1980 price increase.

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[21] Philip K. Verleger, Jr., Oil Markets in Turmoil (Cambridge, Mass.: Ballinger, 1982), pp. 37-38.

THE MAGNITUDE OF THE EFFECTS OF OIL PRICES ON THE ECONOMY

Oil price instability is not a "special interest" issue affecting a small sector of the U.S. economy; it affects the whole economy. In general, the human resources, capital, and natural resources that are the foundations of economic productivity will yield less over a period of oil price fluctuation than they would during a period in which oil prices followed a smooth path (with the same average price level). In the following discussion the effects of oil price fluctuations on U.S. energy-related expenditure are reviewed. The magnitude of energy-related expenditure is then compared with the GNP. The section closes with a brief commentary on the effects of oil price fluctuations on the global economy.

As oil prices rise and fall, U.S. expenditures on energy and energy conservation will rise and fall.

In the U.S. economy there are several categories of expenditure that are strongly affected by oil prices:

- expenditures on crude oil
- expenditures on refining and distribution of petroleum products
- expenditures on natural gas, coal, and electricity
- expenditures on wood, biomass, and operation and maintenance of renewable energy systems
- capital investments in energy supply, and energy research and development
- expenditures on energy conservation investments that substitute capital (or labor) for energy.

The first three categories may be grouped together under the heading of energy consumption expenditure; this figure is estimated by the Department of Energy.[22]

As oil prices increase, expenditures on oil increase in two ways. First, current consumption expenditures rise, as consumers pay higher prices for petroleum products. Second, worldwide capital expenditures by U.S. companies for oil exploration and production will rise.[23] These capital expenditures will have "ripple" effects throughout the economy, as the oil industry increases its purchases of steel, machine tools, computer equipment, and other goods and services.

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[22] U.S. Department of Energy, Energy Information Administration, State Energy Price and Expenditure Report.

Part of the cause of fluctuations in domestic oil industry employment is the fluctuation in global demand for drilling services and hardware. As the low-cost oil resource base of the U.S. is depleted, the U.S. will attract a declining share of global expenditures for non-OPEC exploration and production except when oil prices are high or expected to be high. The magnitude of foreign capital expenditures on oil exploration (and other energy resource development) is large and fluctuates with oil prices. To the extent that oil industries in foreign countries rely on U.S. suppliers for drilling equipment and hardware, the domestic oil service industry is especially vulnerable to boom and bust cycles.

As oil prices increase, expenditures on substitutes for oil increase in several ways:

- Prices of competing fuels such as natural gas are bid upward. Expenditures on competing fuels and electricity also increase as a result of fuel-switching away from oil.
- Prices of new fuel-efficient consumer durables--houses, vehicles, furnaces, and appliances -- are bid upward. Older, less efficient vehicles and appliances are replaced sooner than they would have been in the absence of an oil price increase. Sales of energy-efficient models increase.
- Consumers spend money (and time) on improving the energy efficiency of the existing housing stock, and on keeping furnaces and automobile engines running at peak efficiency. Solar heating is incorporated in housing renovations and additions.
- Capital expenditures in the refining industry are made to extract a greater share of "premium" fuels from crude oil, and to process less expensive crudes.

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[23] The GNP includes capital investments made in other countries by U.S. companies and excludes capital investments made in the U.S. by foreign companies.

- Capital expenditures are made to supply non-petroleum energy and energy-efficient durable goods. Private research and development on alternative energy technology may be accelerated.

- The Federal government may accelerate research and development on alternative energy sources and energy conservation technology. Federal agencies may devote a larger share of man-hours to energy issues. Synfuels may be subsidized; tax credits may be granted for solar energy and methanol.

Aggregate expenditure on energy conservation is very difficult to quantify because efficiency improvements may result from technological change or changes in consumer preferences even in the absence of energy price increases. If consumers buy more fuel-efficient cars after an oil price increase, for example, it may be argued that some of these cars would have been purchased in any event, due to changes in consumer preferences. Displacement of oil heat by electric heat may occur even without an oil price increase.

The magnitude of fluctuations in energy expenditure is large in relation to GNP. The macroeconomic effects of oil price changes are therefore large.

Since 1970, U.S. energy expenditure has fluctuated between 8.5 percent and 14.5 percent of GNP (see Exhibit 1.d). This expenditure figure includes the cost of oil, gas, coal, and electricity but excludes the cost of non-commercial fuels such as wood and biomass. While imported oil is not a "component" of GNP because it is not produced in the U.S., it is reasonable to compare energy expenditures with GNP because the latter is a measure of total expenditure.[24]

The share of GNP spent on energy consumption can be computed by dividing total end user expenditures on energy (as reported by the Department of Energy)[25] by GNP (as reported by the Department of Commerce). Although it may be an

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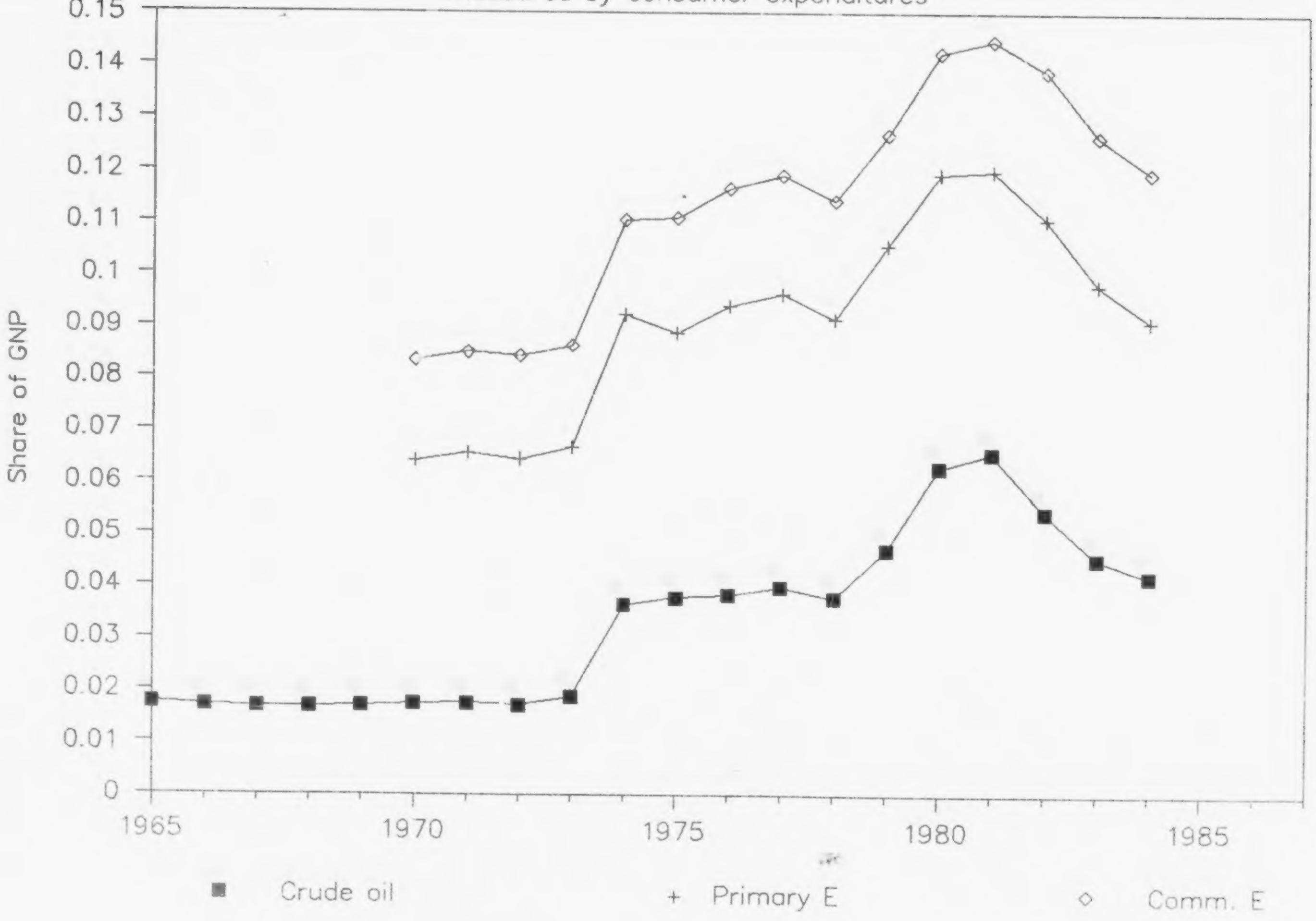
[24] On the "product" side of the National Income and Product Accounts, the cost of imported oil is a debit item because this oil is not produced in the U.S. When "net foreign investment" (a line item in the Foreign Transactions Account) is negative, the U.S. economy may be incurring expenditures greater than the GNP, or there may simply be an increase in foreign ownership of U.S. assets. See George Jaszi and Carol S. Carson, "The National Income and Product Accounts of the United States: An Overview," Survey of Current Business, October 1979, pp. 25-34.

[25] This figure excludes expenditures on wood and biomass (other than that consumed by electric utilities).

Exhibit 1.d

Energy share of GNP

measured by consumer expenditures



important factor in explaining economic trends, it receives relatively little attention because there is a 2-year lag in publication of comprehensive energy expenditure data.[26] The share of GNP devoted to energy consumption is not one of the standard economic statistics collected monthly or quarterly by the Department of Commerce or the Department of Energy. To estimate total energy-related expenditures in the economy it is necessary to estimate the sum of wood and renewable energy costs plus energy-efficiency expenditures plus energy-related capital investment. Capital expenditures on energy supply (including electric and gas utility systems) in 1981 were over $95 billion, or 3 percent of GNP. In the petroleum industry, 1981 capital expenditures in the U.S. were $63 billion;[27] in the investor-owned electric utility industry, construction expenditures in 1980 were $25.718 billion;[28] in the natural gas utility industry, construction expenditures in 1981 were $6.389 billion;[29] additional outlays were made in coal mining, uranium mining, and synfuels. Federal R&D support to energy programs in 1981 was $3.5 billion.[30] Given the fact that energy consumption expenditures are 8.5 to 14.5 percent of GNP, all other energy-related expenditures may be estimated very roughly as 6 percent of GNP during a "boom" period and 3 percent otherwise.

These figures suggest that changes in the price of oil are causing a boom and bust cycle in a segment of the economy equivalent to 12 to 21 percent of the GNP.[31] While the price of oil is not the only cause of fluctuations in energy sector expenditures, it is clearly the most important single factor. The overriding influence of crude oil prices is demonstrated by two observations:

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[26] Data for 1984 were released for publication in December 1986. See U.S. Department of Energy, Energy Information Administration, State Energy Price and Expenditure Report.

[27] The Chase Manhattan Bank, "Capital Investments of the World Petroleum Industry," cited in American Petroleum Institute, Basic Petroleum Data Book, Section V, Table 8a.

[28] Edison Electric Institute, Statistical Year Book of the Electric Utility Industry 1980 (Washington, D.C., 1981), p. 72.

[29] American Gas Association, Gas Facts 1981 (Arlington, VA: AGA, 1982), p. 183.

[30] Energy Research Advisory Board, Guidelines for DOE Long Term Civilian Research and Development, Volume II: Infrastructure (December 1985), p.4.

[31] This figure does not include foreigners' purchases of U.S. oil companies, oil and gas acreage, or other assets, nor does it include foreigners' income from investments in the U.S.

- Energy consumption expenditure is strongly correlated with the crude oil cost component of petroleum purchases, over the 1970-1984 period (see Exhibit 1.b). This crude oil expenditure is estimated by measuring "petroleum products supplied" in equivalent barrels of crude oil, and multiplying this volume by the average refiner acquisition cost of crude.[32]

- Expenditures on electricity transmission, distribution, and non-fuel generating costs represented a nearly constant share of GNP over the 1970-1984 period. (In Exhibit 1.d these costs are illustrated by the gap between primary energy expenditure and total energy expenditure.)

Because energy-related expenditure is equivalent to roughly 12 to 21 percent of GNP, the macroeconomic effects of a boom and bust cycle in energy-related expenditure are significant. In 1986, for example, the oil price decline had several effects:

> Probably the most important special factor affecting the U.S. economy in 1986 was the sharp drop in world oil prices, which was promptly reflected in domestic prices... The sharp decline in oil prices had pronounced adverse effects on the domestic oil and gas industry. Real investment in this industry declined by more than $10 billion in the first half of 1986, accounting for more than half of the decline in real business fixed investment. Employment in the domestic oil and gas industry fell by nearly 150,000, mainly in the first half. Further employment losses occurred in regions heavily dependent on the oil and gas industry... The decline in consumer prices was clearly attributable to lower oil and gas prices... The fall in oil prices, inflation, and inflationary expectations also played a critical role in the sharp decline in nominal interest rates.[33]

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[32] Because this calculation does not contain an allowance for refinery gain, it understates crude oil cost. A correction for refinery gain is not likely to change the shape of the curve in Exhibit 1.b, however.

[33] U.S. Council of Economic Advisors, Economic Report of the President, January 1987, pp. 25-26.

There is evidence, in fact, that oil price spikes and price increases have been an important factor contributing to recessions in the U.S. economy over the 1947-1983 period. Research by James Hamilton, a professor at the University of Virginia, shows that the correlation between recessions and oil price shocks to the U.S. economy is too strong to be merely coincidental:

> ... all but one of the recessions in the United States since World War II were preceded -- typically by about nine months -- by a dramatic increase in the price of crude petroleum.
>
> ... the oil price increases resulted from events largely exogenous to the U.S. economy.
>
> ... oil supply disruptions stemming from political instability in the Mideast, rather than being isolated events peculiar to the last decade, have been a recurrent fact of life ever since World War II.[34]

Among commodities, crude oil occupies a unique position because annual expenditures on crude oil are large in relation to GNP, and other energy expenditures are large and fluctuate in response to oil price changes. The crude oil expenditure associated with petroleum products supplied was roughly 4 percent of GNP in 1984 (see the lower curve in Exhibit 1.d). The price swings of internationally traded agricultural commodities tend to be independently determined, so that increases in the price of one are often offset by decreases in the price of another. No single commodity market, such as wheat or copper, is likely to have macroeconomic effects on the U.S. economy as large as the effects of oil market fluctuations.

Because energy is a vital input to the production process, the cost of energy will always be important to economic growth. Energy is not simply a consumer good; it is a critical factor input in the production process. The fundamental production inputs to the global economy may be classified as energy, land, labor, capital, and technology. While other fuels such as natural gas and coal can substitute for oil in the short run (in time periods less than a year), it is relatively difficult for land, labor, capital and technology to substitute for energy over short time periods.

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[34] James D. Hamilton, "Historical Causes of Postwar Oil Shocks and Recessions," The Energy Journal 6,1 (January 1985), pp. 97, 99.

The cost of oil will be a major determinant of energy costs as long as the competitive floor to oil prices is no higher than the Btu equivalent cost of other energy sources that can substitute for oil (for example, other transportation fuels). Because Mideast oil reserves are very large, it appears that oil will not "price itself out of the market" for a very long time. In the current energy market the competitive floor to oil prices is low enough to displace natural gas and coal in stationary applications such as boilers and furnaces. There is really no competitive substitute for oil in the transportation fuel market unless oil prices are artificially raised above the competitive floor. An oil price crash will continue to be a "threat" to other fuels for some time. These observations suggest that the macroeconomic effects of oil price fluctuations will be substantial for at least a few decades.

Oil price instability causes shocks to the global economy, not just the U.S. economy.

Major changes in oil prices have a significant effect on international trade.and therefore affect the economies of all countries. Among oil-importing countries the United States may be more resilient and better prepared to face oil price shocks than many other nations. The economic implications of a cyclical pattern of oil prices are a serious concern to the International Monetary Fund:

> ... adverse effects would follow if oil prices were to become much more variable in the future than they have been in the past. If oil prices were henceforth to fluctuate randomly between, say, \$15 and \$25 a barrel, this would be equivalent to a succession of shocks to the world economy equivalent to well over 1/2 of 1 percent of GNP. Shocks of this magnitude could be seriously destabilizing, and it would presumably be a matter of time before countries took action to insulate themselves from them...
>
> Another set of costs associated with oil price changes is the adjustment costs associated with sustained oil price changes. ... These costs tend to get ignored in flow-oriented analyses. Such analyses often conclude that neither the level nor the distribution of world income would be much affected by a sustained change in oil prices that was later reversed. This ignores, however, the fact that because of adjustment costs, global

> wealth ends up lower under the hypothesized conditions than it would have if actual (or expected) relative prices had not changed.[35]

It is difficult, if not impossible, to "shield" the U.S. economy from events that adversely affect the global economy. For simplicity the following discussion focuses on the effects of a cyclical pattern of oil prices on the U.S. economy. It is reasonable to assume that the seriousness of these issues would be reinforced by a broader analysis with an international perspective.

ECONOMIC PROBLEMS CREATED BY A CYCLICAL PATTERN OF OIL PRICES

The Federal government should be concerned about the boom and bust cycle of world oil prices because this cycle adversely affects the U.S. economy in several ways. The fact that oil prices today are low in relation to 1979-1985 prices should not be considered an indication that our energy problems have gone away.

In the following discussion, effects of oil price volatility are described in relation to several measures of the health of the economy:

- inflation
- unemployment
- labor productivity
- security of financial institutions
- international competitiveness of U.S. industry.

The role of the Federal government is then discussed, with special attention to the effect of changing Federal policies on the boom and bust cycle, and the effect of the cycle on Federal expenditures and tax receipts.

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[35] International Monetary Fund, World Economic Outlook: April 1986 (Washington, D.C.: IMF, 1986), pp.46-47.

Inflation is increased by a cyclical pattern of oil prices.

The experience of the 1970s demonstrates the inflationary effect of oil price increases:

> With the removal of [price and wage] controls, the inflation rate and interest rates rose in 1973, exacerbated at the end by the surge in world oil prices... the second oil price shock (in early 1979) contributed to a further upsurge of inflation and interest rates.[36]

According to one study the 1973-1974 oil price increase raised the rate of inflation "by 4 percentage points in 1974 and almost 2 percentage points in 1975."[37]

When oil prices increase, the rate of inflation is stimulated in several ways:

1. The increased cost of crude oil is passed on in the form of increased costs of petroleum products, and these costs are passed on in the form of increased costs of other goods and services.

2. Prices of competing fuels such as natural gas are bid upward. Prices of new fuel-efficient consumer durables -- houses, vehicles, furnaces, and appliances -- are bid upward as energy costs rise.

3. To prevent a decline in real income, U.S. workers will seek wage and salary increases that equal or exceed cost of living increases. In unionized industries employers may have to grant cost of living increases to comply with labor agreements. In other industries employers may grant these increases in the belief that they are reasonable; that everyone in the economy can keep up with the cost of living and that earned income is the means to do so. In fact a rise in world oil prices (absent a currency adjustment) must force the U.S. to accept a decline in real income or a transfer of wealth to foreigners (via the sale of assets to

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[36] U.S. Council of Economic Advisors, Economic Report of the President, January 1987, p. 30.

[37] Knut Anton Mork and Robert E. Hall, "Energy Prices, Inflation, and Recession," Energy Journal 1,3 (July 1980), p. 54. See also Knut Anton Mork and Robert E. Hall, "Energy Prices and the U.S. Economy in 1979-1981," Energy Journal 1,2 (April 1980).

foreigners, or via increased indebtedness to foreigners).[38]

4. To make consumers (and not stockholders) bear the burden of wage and salary increases, U.S. companies may raise their prices. Inflation may spiral, as companies raise their prices in anticipation of cost increases. Companies may also raise prices in response to their competitors' price increases.

Other effects on inflation are possible. Because a major change in oil prices creates a transfer of purchasing power from oil-importing nations to oil-exporting nations, spending and investment patterns may be altered suddenly. A sudden increase in demand in certain sectors of the economy would create upward pressure on prices in those sectors. At a minimum, the balance between spending and saving is likely to be altered:

> a key factor behind the recession following each of the two rounds of price increases [1973-74 and 1979-80] was a temporary rise in the world's saving ratio, reflecting differences in the short-run spending propensities as between oil exporting and oil importing countries.[39]

By increasing the rate of inflation, oil price increases raise nominal interest rates. By altering international capital flows, oil prices could also affect real interest rates.

If oil prices are cyclical, the inflationary effects of price increases may be repeated in every upswing in the price cycle. It is not likely that effects 3 and 4 will operate symmetrically as oil prices fall -- that employers will automatically drop wages, salaries, and prices. The long-term effect of cyclical oil prices on inflation may therefore be worse than the effect of a "one-time" oil price increase.

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[38] In this respect a rise in world oil prices has an effect on U.S. consumers that is similar to a decline in the value of the dollar relative to other currencies. The effect of rising oil price on the cost of living may be offset, however, by a strengthening of the dollar against the mark and the yen.

[39] International Monetary Fund, World Economic Outlook: April 1986 (Washington, D.C.: IMF, 1986), p.25.

Unemployment may be increased by a cyclical pattern of oil prices.

There are two ways in which a cyclical pattern of oil prices may increase unemployment:

1. Changes in oil prices create shifts in labor demand, and unemployment may be increased by the continual process of adjustment to these demand shifts. When oil prices decrease, unemployment rises in the oil industry, in industries that provide raw materials and equipment to the oil industry, and in states in which the oil industry is a major source of employment. When oil prices increase, consumers and businesses reduce their purchases of energy-intensive goods and services (e.g. large cars, airplane travel), and these shifts in demand may cause layoffs in some sectors of the economy.[40]

2. Because oil price increases are inflationary, governments may try to fight inflation by slowing down their economies (e.g., by raising interest rates). The global experience of the 1978-1983 period demonstrates that a recession may result from policies designed to reduce inflation:

   > ... the anti-inflationary tightening of financial policies that followed the oil price increases of the late 1970s also aggravated the subsequent recession.[41]

   If foreign governments pursue this course, U.S. exports and employment in export industries will suffer.

Other adverse effects are also possible. If the Federal government responds to oil price swings by making major changes in Federal spending and taxation patterns, for example, shifts in labor demand may be more pronounced. In 1979-1985 the synfuels industry (and to an extent, the Western coal industry) passed through a boom and bust cycle that was exaggerated by shifts in Federal policy toward synfuels.

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[40] In a period of high energy prices this effect will be offset, in the economy as a whole, by an increase in labor demand associated with substitution of labor for energy. See Dale W. Jorgenson, "The Great Transition: Energy and Economic Change," The Energy Journal 7,3 (July 1986), p.9.

[41] International Monetary Fund, World Economic Outlook: April (Washington, D.C.: IMF, 1986), p.25.

During the peak of an oil price cycle the OPEC nations' demand for dollars could make the dollar rise against the currencies of other oil-importing nations.[42] Under these circumstances employment will be reduced in U.S. industries in which international competition is most intense. In the trough of an oil price cycle, however, the reduced demand for dollars could lower the value of the dollar and thereby increase employment in U.S. export industries.

The magnitude of unemployment effects caused by shifts in labor demand will be affected by industry expectations concerning the permanence of the shift. If prices drop in the oil industry, for example, the number of layoffs of skilled workers with specialized expertise will be depend on firms' price expectations. If prices are expected to rebound in 6 months the unemployment effect will be moderated; if the price reduction is expected to be permanent the unemployment effect will be maximized. Because expectations cannot be predicted, estimates of unemployment effects are difficult to predict.

The unemployment effects of a prolonged (5-year) downturn in U.S. oil exploration and production (E&P) have been estimated by the American Petroleum Institute (API), based upon Department of Commerce data. API estimated that each $1 billion cut in E&P spending results in the loss of 10,893 jobs in petroleum E&P and 8,903 jobs in 19 other industries--machinery and equipment, primary iron and steel, transportation and warehousing, etc.[43] A $27.5 billion cut in E&P (sustained for 5 years) would therefore lead to a loss of 300,000 jobs in the oil industry and 245,000 jobs in industries affected indirectly. API estimated in June 1986 that cuts of this magnitude will occur if oil prices remain at or below $15 per barrel (in 1985 dollars) through 1991.[44] The Council of Economic Advisors estimates that the 1986 decline in employment in the oil and gas industry was 150,000 jobs, or half the long-term loss envisioned by API.[45] It is true that the negative effects on employment in oil and gas must be balanced against employment increases resulting from growth in other sectors. However, the social and economic disruption should not be minimized.

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[42] Because OPEC nations collect oil revenues in dollars, and because the U.S. is less dependent on oil imports than West Germany, Japan, Italy, France, and other developed nations, the effect of an oil price increase may be to strengthen the dollar. Under these conditions foreign investors have an incentive to purchase U.S. assets and securities, and the net capital infow will sustain a negative balance of merchandise trade.

[43] American Petroleum Institute, Two Energy Futures (Washington, D.C., July 1986), cited in "Loss of E&P professionals seen problem when industry recovers," Oil & Gas Journal, June 30, 1986, p. 27.

The unemployment effects of the 1973-1974 oil price increase were estimated in a study completed in 1980, based on a macroeconomic model designed to give special consideration of the energy sector. The model showed significant effects on employment:

> Large and unanticipated changes in the price of energy are found to have substantial disruptive effects on the economy. ... The effects on employment can be expressed as an increase in the unemployment rate of about 1 percentage point in 1974, rising to 1.9 percentage points in 1975, and tapering off thereafter. The energy price shock was clearly a major cause of the 1974-1975 recession and inflation.[46]

Labor productivity is reduced by a cyclical pattern of oil prices.

Over the long term, increases in GNP per worker must be achieved by increases in labor productivity. Labor productivity is measured by a ratio of real value added per unit of labor input.

A cyclical pattern of oil prices will tend to reduce U.S. labor productivity in several ways:

1. When oil prices rise sharply the U.S. begins to extract higher-cost energy resources, including higher-cost oil resources. The incremental expenditure on capital and labor per MMBtu of energy delivered to end users rises. More capital

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[44] "Loss of E&P professionals seen problem when industry recovers," Oil & Gas Journal, June 30, 1986, p.29.

[45] U.S. Council of Economic Advisors, Economic Report of the President, January 1987, p.25.

[46] Knut Anton Mork and Robert E. Hall, "Energy Prices, Inflation, and Recession," The Energy Journal 1,3 (July 1980), p. 54.

and labor inputs are therefore required per unit of output in the economy as a whole.

2. When energy prices increase, labor inputs are substituted for energy inputs to manufacturing. New capital investments that improve energy efficiency will be favored over other capital investments, possibly including investments that improve labor productivity. Labor productivity may be reduced so that energy productivity may increase.

3. Changes in oil prices create shifts in labor demand, and the adjustment process can be very costly. In the trough of an oil price cycle, skilled workers in the oil, gas, and coal industries are unable to use their professional skills; they must take unskilled jobs or learn new skills. In the peak of an oil price cycle, the oil and gas industry must train unskilled workers. If workers are reluctant to move from one part of the country to another in response to shifts in labor demand, the friction involved in adjusting to shifts in labor demand may be substantial.

Economic analysis suggests that the rise in energy prices in the 1970s had a significant negative effect on labor productivity:

> Increased energy prices have substantially reduced the rate of productivity growth. This decrease in productivity growth is the most important explanation for the slowdown in economic growth.[47]

The effects of energy prices on labor productivity have also been noted by the Council of Economic Advisors:

> Several factors contributed to the slowdown in labor productivity growth that began in the early 1970s... Large increases in the price of energy in the middle and late 1970s diminished the economic efficiency of much existing capital, and required that new investment and research and development be directed toward improving energy efficiency.

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[47] Dale W. Jorgenson, "The Great Transition: Energy and Economic Change," The Energy Journal 7,3 (July 1986), p. 12.

> ... the recent decline in energy prices should allow for some labor productivity improvement, especially in energy-intensive industries.[48]

The security of U.S. financial institutions is reduced by a cyclical pattern of oil prices.

There are three ways in which the security of U.S. financial institutions is reduced by oil price instability:

1. Oil price instability increases the riskiness of investments in the economy generally. The risk of high oil prices creates a higher risk of increases in inflation and interest rates. Unpredictable shifts in oil prices also create "winners and losers" in the economy. The business environment is made more risky by oil price instability.
2. The credit worthiness of loans to developing countries is reduced by cyclical oil prices. Oil price increases threaten the ability of oil-importing nations (e.g., Brazil) to continue to pay interest on their debt.[49] Oil price decreases threaten the ability of oil-exporting nations (e.g., Mexico) to continue interest payments.
3. Investments in the oil and gas industry are made more risky by oil price instability. A change from a stable oil price regime to an unstable oil price regime may catch financial institutions unprepared for the increased risk associated with their existing holdings.
4. Investments in real estate or local service industries in oil-producing states are made more risky by oil price instability.

The vulnerability of U.S. financial institutions to oil price changes will depend on their ability to recognize and anticipate oil price instability.[50] The level of risk associated with oil and gas investments may be underestimated by financial institutions, and their oil price expectations during a "boom" period may be unreasonably optimistic. In the peak of an oil price cycle, commercial banks and savings and loan associations located in oil-producing states tend to invest more heavily in oil and gas companies and properties, through the purchase of securities or through commercial lending to independent oil companies. In the trough of an oil price cycle, bank failures result. Similarly, the level of risk associated with non-oil investments in oil-producing states may also be underestimated by financial institutions. Risk associated with real estate investments in Texas and Louisiana, for example, may be underestimated.

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[48] U.S. Council of Economic Advisors, Economic Report of the President, January 1987, pp. 46-48.

[49] Although the February 1987 decision by Brazil to halt interest payments followed a period of low oil prices, the growth potential of the Brazilian economy over the 1979-1985 period was adversely affected by high oil prices.

The downturn in oil prices that occurred in 1986 placed a significant strain on financial institutions in oil-producing states. One of the consequences of this strain is that additional funding of FSLIC may be necessary to ensure solvency. Even before 1986, energy investments that were undertaken on the assumption of high oil prices put a strain on selected banks such as Penn Square and Continental Illinois. It is unclear, however, whether the experience of the recent past is an indicator of the likely response of financial institutions to the peaks of future oil price cycles. If these institutions can diversify their investment portfolios to minimize vulnerability to oil price fluctuations, the need for Federal intervention to protect depositors will be greatly reduced.

The international competitiveness of U.S. industry may be affected by currency fluctuations. Unstable prices increase the business risk associated with currency fluctuations.

Any major change in oil prices will alter the terms of trade among nations and thereby create pressure for currency adjustments. If the effect of an increase in oil prices is to strengthen the dollar, U.S. manufacturing exports will be adversely affected. If the effect of an increase in oil prices is to weaken the dollar, capital will tend to flow out of the United States, industries dependent on imported raw materials will be adversely affected, and retailers of imported goods will be affected. While it is difficult to predict the direction of currency adjustments, there can be no doubt that oil price instability creates an increase in the likelihood of such fluctuations, and therefore an increase in business risk.

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[50] Regulatory restrictions may limit the ability of commercial banks and savings and loans in oil-producing states to diversify their investments geographically. The risk of oil-related loan defaults may be spread over a smaller number of commercial banks than is economically optimal.

In addition to the risk of currency fluctuations, sudden oil price changes may create a risk of a breakdown in the international monetary system. After the 1973-1974 oil price shock there was some concern that the international monetary system would have difficulty adjusting to the sudden global shift in purchasing power. The following statement is perhaps illustrative:

> It is remarkable that the great shock that was administered to the world economy by the sudden quadrupling of the price of crude oil did not create an international-payments crisis. The system of floating exchange rates was able to absorb the impact. It would be wrong, though, to conclude that flexible exchange rates can single-handedly solve the enormous new transfer problem that the world is now facing.[51]

While the degree of concern expressed in 1975 may have been exaggerated, the strain imposed on the monetary system by oil price shocks should not be overlooked.

When oil prices are unstable and unpredictable, there is a greater risk that we will consume our remaining domestic oil resources when we do not need them the most -- that we will consume them too soon or too late.

Every oil price "spike" allows oil producers and resource owners to sell oil and oil reserves at prices well above cost -- to capture profits that are termed "economic rents" by economists.[52] While an unusually high price level gives producers an economic incentive to bring on marginal sources of production that yield no economic rent, a large fraction of total production in boom times will come from lower-cost sources that yield substantial rents. The realization of such rents in the U.S. economy is an important gain which helps to offset the otherwise negative effects of an oil price increase on the economy. When oil prices are volatile and unpredictable, opportunities to capture economic rent may be permanently lost; U.S. producers may be caught unprepared for sudden oil price increases, and capture only the modest economic rents available in the "trough" of an oil price cycle. The economy forgoes the offsetting gain, deepening the recession caused by a price increase.

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[51] George N. Halm, A Guide to International Monetary Reform (Lexington, Mass.: Lexington Books, 1975), p. 107.

[52] Typically the producer will share economic rent with the owner of the mineral rights; the owner may even capture the total economic rent.

To maximize the present value of economic rent from U.S. oil resources when foreign oil production is the "swing" supply, producers must reduce production, particularly of high-cost resources, during the trough of each price cycle, and yet maintain enough production capacity to be able to increase oil production quickly before the peak is past. If future oil prices were known with certainty, the industry could try to rely heavily on domestic production during "peak" periods and rely heavily on imports during "trough" periods. Because oil prices are uncertain, there is a need for "peaking capacity" at all times -- capacity that allows the industry to respond to the peak of a price cycle before the peak is past. Idle drilling rigs, offshore barges, and offshore exploratory platforms, for example, represent different forms of peaking capacity. Shut-in wells and undeveloped marginal resources also represent forms of peaking capacity. The industry's ability to pay for peaking capacity is constrained, however, by the need to produce in "trough" periods to generate cash flow for exploration, and by the performance characteristics of producing wells.[53] It is interesting to note that maintaining peaking capacity also tends to dissipate economic rents. This serves to discourage exploration.

Because future oil prices are uncertain and because a time lag of several years is required to increase domestic oil production capacity in new fields (especially in frontier areas), there is a risk that a portion of domestic production will occur too soon or too late to maximize the present value of economic rent. This problem is most severe where lead times are the longest -- typically in frontier areas. There is a risk that domestic oil production from new fields will be too high when oil is cheap, and too low when oil is expensive; that our scarce domestic resources will be produced when they are less valuable to the economy. There is a risk, for example, that oil prices will be moderate during the 1990s and then increase very sharply after the year 2000, but domestic resources will be depleted too rapidly in the 1990s and the nation will be unprepared for the severe (OPEC-induced) price increases likely in the 2000-2010 period. Conversely there is a risk that the nation will postpone development of its best oil acreage in the

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[53] This discussion of peaking capacity is intended to be only illustrative. The economic relationships involved in "optimal" industry performance are complex.

1990s, only to find that oil demand collapses after 2000 due to advances in synfuel and renewable energy technology, major gas reserve discoveries, or other factors.

The timing of development of our nation's oil resources will be influenced by Federal leasing policies as well as private-sector decisions. Among the policy tools available to the government are Outer Continental Shelf (OCS) lease sale schedules, leasing of the coastal plain of the Alaska National Wildlife Refuge, production diligence regulations, and sliding scale royalties that penalize (or reward) accelerated production. If there is a lag in offering OCS lease tracts, for example, the tracts may not be developed in time to achieve full production in the peak of an oil price cycle, when production is most needed.

The concept that oil price uncertainty makes it difficult to maximize the present value of economic rent is different from the familiar notion that dependence on imports makes the U.S. "vulnerable" to price increases. While it is certainly true that increasing domestic production will reduce the nation's vulnerability to an oil price increase (or an oil supply disruption) in the short run, the more rapid short-run depletion of domestic resources may increase the nation's vulnerability in the long run (e.g., the following decade).

In other words, the problem is not simply that oil prices might increase in the 1990s. The problem is that we do not know when they might decrease and when they might increase yet again. Thus we do not know when we might gain the most from increasing production from our remaining domestic resources. While a decision by Saudi Arabia to postpone or accelerate production has no great "cost" to that country over the next 30 years, given the size of Saudi reserves, a decision to postpone or accelerate production of U.S. resources could be very costly. The global distribution of resources gives the greatest decision-making flexibility to those nations possessing the greatest reserves and undiscovered resources per barrel of current production.

The volatility and unpredictability of oil prices would make it difficult to maximize the present value of economic rent, even if the U.S. exported oil rather than importing it. The substitution between domestic and foreign production creates a competition for peak period rents -- for meeting the price peaks when they occur -- that would exist regardless of the import or export status of the United States.

In the context of Federal land management policy, maximizing the present value of economic rent is the ultimate management objective. The amount of economic rent depends upon the timing of development. In an era of unstable oil prices, dependence upon oil imports makes it difficult to ensure that Federal policy will result in capturing rent during the peaks rather than the troughs.[54]

The instability of oil prices increases the need for the Federal government to adopt a longer-term perspective toward oil and gas leasing issues. Influenced by current political controversies, policy perspectives are sometimes short-term and short-sighted.

Currently Federal energy policy does not attempt to dampen the boom and bust cycle in the energy industry. In many ways it may exacerbate it.

There are three ways in which the Federal government exacerbated the boom and bust cycle in energy over the 1972-1985 period:

1. Federal price controls on oil tended to increase the demand for OPEC oil and thereby facilitate the 1979-1980 price increase. Price controls tended to suppress domestic oil production and stimulate domestic oil demand. In the words of a leading economist,

   > ... the growth in OECD imports after the first oil crisis was due entirely to a misguided attempt by the United States to achieve equity in income distribution through intervention in domestic energy markets. The resulting rise in U.S. oil imports contributed mightily to the second world oil crisis that followed the Iranian Revolution.[55]

2. The Natural Gas Policy Act of 1978 established a system of price controls that tended to create a boom in exploration for certain categories of gas classified as high-cost. Prices for new gas were artificially stimulated by the practice of averaging the cost of new, "high-cost" gas with the cost

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[54] If oil prices were cyclical but followed a predictable pattern it would be possible for both government and the private sector to schedule oil exploration activity accordingly.

[55] Dale W. Jorgenson, "The Great Transition: Energy and Economic Change," The Energy Journal 7,3 (July 1986), p. 11.

of old gas subject to price ceilings. As gas supply grew and demand fell, the boom in gas exploration was followed by a bust.[56]

3. The Federal government spent more money on energy research and development when oil prices were high than when oil prices were low. Spending patterns on "long-term" R&D tended to follow current price expectations, which in turn followed current prices, despite the long-term nature of R&D benefits. The peak in federal R&D support to energy programs occurred in 1980.[57]

   Political support for the Synthetic Fuels Corporation followed a boom and bust cycle in parallel with oil prices. The level of SFC support cannot be measured by R&D spending. The incentive given to private industry in the form of expectations of financial support peaked, perhaps, in 1981.

Even today the Federal government contributes to oil price instability by preserving the windfall profits tax. If the windfall profits tax remains in effect and oil prices return to high levels, the effect of this tax will be to dampen incentives for U.S. production of crude oil and thereby decrease elasticity of demand for OPEC oil. Any policies that make the demand for OPEC oil less elastic tend to contribute to oil price instability.

The Federal government does not have a program to dampen the boom and bust cycles of the oil industry, and there exists no "model" upon which such a program could be based.[58] Although the Federal government protects farmers from fluctuations in prices of certain agricultural commodities, these programs were not designed to achieve specific goals at least cost. The agricultural commodity programs serve a number of political objectives, and were not designed specifically to dampen the effects of price fluctuations in internationally traded commodities.

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[56] In 1985 the Federal Energy Regulatory Commission proposed a "block billing" system to remedy this problem, stating that "The rolled-in ratemaking policy encourages the development of 'boom and bust' cycles." See Federal Energy Regulatory Commission, "Notice Requesting Supplemental Comments," October 30, 1985, p. 41.

[57] Energy Research Advisory Board, Guidelines for DOE Long Term Civilian Research and Development, Volume II: Infrastructure (December 1985), p. 4.

[58] Guidelines proposed by economists for the reform of agricultural commodity programs might be used to define a "model" commodity program. See, for example, U.S. Council of Economic Advisors, Economic Report of the President, January 1987, pp. 174-177.

The Federal government is already committed to absorbing a portion of the economic losses associated with the cyclical nature of the oil industry. These losses may affect the Federal deficit.

As a purchaser of goods and services the Federal government is affected by oil price volatility in much the same way that consumers and businesses generally are affected. There are several additional ways in which the Federal government is affected by oil price swings, however:

1. Federal oil and gas lease revenue fluctuates with oil prices.

2. The Federal government insures banks (through FDIC) and savings and loan associations (through FSLIC) that have heavy investments in oil-producing states. When oil prices fall, some banks may be in default; the government must then act to prevent depositors from losing their money.

3. Federal corporate income tax revenue from oil and gas companies fluctuates with oil prices. These revenue fluctuations may be offset, however, by fluctuations in tax receipts from companies in energy-consuming sectors of the economy.

4. To the extent that total national output is reduced by the process of adjustment to higher (or lower) oil prices, Federal tax receipts are lower than they would be under a regime of stable oil prices.

5. Any increase in unemployment will tend to raise Federal outlays and reduce revenues. Unemployment increases the cost of job training and income maintenance costs and reduces tax receipts. State requests for revenue-sharing may increase as unemployment compensation outlays rise.

6. At the peak of an oil price cycle, nominal interest rates will rise as inflation rises, and the government may raise interest rates further to combat inflation. The rise in interest rates increases the cost of servicing the national debt. Given these relationships it is clear that the Federal budget is affected by the cyclical nature of oil prices.

ECONOMIC PROBLEMS CREATED BY DEPENDENCE ON OIL IMPORTS

Although the economy will be affected by oil prices regardless of the level of imports, there are several reasons to be concerned about the effect of oil import dependence on the nation's economic health.

In this section, the following concerns about oil import dependence are discussed:

- income transfers to oil-exporting nations
- payments for imported oil that exceed the "avoided cost" associated with this oil
- increased inflationary pressures
- increased business risk associated with currency fluctuations.

Each of these concerns might be cited to support policies to reduce oil imports. The first issue is perhaps the weakest argument for reducing imports, but the most familiar.

Because the world oil market is not workably competitive, dependence on oil imports creates the potential for an excessive transfer of income or wealth to oil-exporting nations.

If oil markets were competitive, oil would be priced at its long-run marginal cost. Any producer, such as Saudi Arabia, that could produce oil at a cost below this marginal cost would be legitimately entitled to the "extra" profit (economic rent) associated with lower-cost oil. Because oil prices are well above the competitive floor, oil-exporting nations collect "excess" revenue from oil-importing nations.

As long as the United States is dependent on oil imports, the effect of an OPEC-induced price increase is an income transfer from U.S. oil consumers to foreign oil producers and foreign governments (including OPEC nations). The economic rent on imported oil is captured by foreigners. The more dependent the U.S. is on oil imports, the more income or wealth will be transferred to foreigners. Americans may transfer this income by letting oil exporters purchase a larger share of U.S. output of goods and services; by letting oil exporters invest in U.S. securities and purchase U.S. capital assets; or by becoming indebted to oil exporters. None of these choices is attractive.

If the United States consistently produced more than enough crude oil to meet domestic needs for petroleum products, oil price increases would not cause income transfers to oil-exporting nations. If the nation were self-sufficient in oil but there were no oil exports, even during a period of high oil prices, oil price increases would cause income transfers only among Americans.[59] If the nation were an oil exporter, oil price increases would cause income transfers from foreigners to Americans.

The fact that cartel pricing and import dependence leads to income transfers does not demonstrate, however, that the United States can or should be self-sufficient in energy. Even when oil prices are set by a cartel, imported oil may be less expensive than the cost of producing an equivalent quantity of domestic oil (or an equivalent substitute for oil from a resource base depleted of low cost oil). Oil imports allow the United States to conserve some of its resources for future periods when prices are higher. The income transfers that occur from the United States to less-developed oil-exporting countries such as Mexico, Venezuela, Nigeria, and Indonesia may serve ethical and foreign policy objectives. Studies that estimate the effects on GNP of a rise in the cost of imported oil should be interpreted carefully. The GNP is not necessarily "reduced" by dependence on oil imports, even though it is reduced by the combined effect of import dependence plus increases in world oil prices. As long as it is less expensive, in the long run, to import more oil rather than achieve greater energy self-sufficiency, the GNP will be increased by international trade in oil just as it is increased by international trade in other commodities whose markets are also imperfectly competitive.

Because oil prices are volatile and unpredictable, private firms may not pursue investments that can displace oil imports over the long term and be cost-effective for the nation as a whole.

In an era of unstable oil prices, the threat of a price crash may prevent the competitive marketplace in the United States from following a path of greater energy self-sufficiency that would be cheaper, in the long run, than dependence on imports. There is a basis for concern that the instability of oil prices makes the United States vulnerable to price gouging -- to being charged even more for energy supplies than it would cost the U.S. to meet its energy needs in an orderly market. Dependence on imports may, in the long run, fail to be the "bargain" that it appears to be at present price levels (below $20 per barrel). The threat of a price war may deter investments that, in retrospect, would clearly have been be cost-effective. By creating price risk for U.S. oil producers and other U.S. energy suppliers, OPEC may be able to charge more for oil than it is actually worth to the United States.

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[59] Because oil producers have an incentive to increase oil production during a period of high oil prices in order to maximize profit per barrel, a nation that is self-sufficient in a price trough period will probably export oil during a peak period unless exports are prohibited by the government or profits on exports are taxed away.

The income transfers to oil-exporting nations that may be considered truly excessive are those associated with oil import costs higher than the costs the United States would have to follow to achieve oil self-sufficiency -- higher than the "avoidance cost" of oil imports. Suppose, for example, that a stable price of $25 per barrel were sufficient to achieve U.S. self-sufficiency by promoting domestic oil production, displacement of oil by other fuels, and energy conservation measures. Under these conditions imported oil prices that average more than $25 could be considered excessive.

It would be naive to regard the current trough of the oil price cycle as evidence that the market is now fundamentally competitive and that real oil prices cannot return to the levels of 1980-1981. On the contrary, a price war is a very effective way of causing non-OPEC nations to defer investments that would reduce OPEC's market share, either by reducing oil demand or by increasing non-OPEC supply. Without an occasional crash in prices, it is more difficult for OPEC to preserve its market share. While it appears that the price crash of 1986 was initiated by Saudi Arabia to preserve its own market share, rather than OPEC's market share, the effect of Saudi Arabia's action was to preserve the market share of all low-cost oil-exporting nations.[60]

Because complete energy self-sufficiency may be prohibitively expensive, the choice facing the United States should not be perceived simply as a choice between imports or no imports. In retrospect the least-cost level of oil imports for the United States may be measured by the level at which the marginal cost of foreign oil equals the avoidance cost associated with that oil, on a present value basis. Because oil prices are not predictable, it is clear that the volume of imports achieved by the U.S. energy marketplace may exceed the least-cost level of oil imports, in retrospect. What is less clear is whether the market errs on a prospective basis; whether the market over-reacts to the threat of an oil price war, deferring investments that may be desirable from the standpoint of the nation as a whole. If the market over-reacts to the risk of price wars, the level of oil imports will not be economically efficient.

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[60] The hypothesis that Saudi Arabia plans to carry out repeated price wars to maintain its market share has been descrebed by API as the "New Cartel View." See American Petroleum Institute, Domestic Petroleum Production and National Security, pp. III-2 to III-3.

In an era of cyclical oil prices, increased dependence on oil imports is likely to increase inflationary pressures.

When oil prices rise, Americans may try to "escape" an income transfer to oil-exporting nations by raising prices and wages. Such attempts to avoid a decline in real income will only exacerbate inflation. While an oil price increase will be inflationary even in the absence of oil imports, the income transfer associated with imports is likely to increase inflationary pressures.

The short-term effect of a price increase applied to domestic oil is an income transfer from oil consumers to oil producers. As consumers, Americans suffer from an increase in oil prices. The loss of purchasing power is offset, however, by the receipt of economic rent associated with domestic oil production. If the nation were not dependent on crude oil or petroleum product imports, all of the economic rent associated with domestic consumption of petroleum products would be captured by Americans -- by U.S. royalty owners, producers, state governments, and the Federal government. This economic rent may be distributed in the form of increased oil industry profits; increased Federal (and oil producing state) income tax, lease bonus, and royalty receipts; increased private royalty payments and lease values; and increased wages and salaries in the oil producing states. Receipt of economic rent softens the blow of rising oil costs.

Inflation is, in part, a game in which cost increases are passed on in the hope that they will not come back. At the peak of every oil price cycle, Americans may use inflationary wage and salary increases to try to offset the decline in real income caused by dependence on oil imports. Without the receipt of oil-related economic rent in some form, Americans are more likely to try to increase wages and salaries in order to escape the burden of rising imported oil costs. There is no escape, of course; Americans can only shift the consumer burden to other Americans. The U.S. economy can only be injured by the inflationary effect of oil import dependence.

In an era of cyclical oil prices, increased dependence on oil imports increases the business risk associated with trade imbalances and currency fluctuations.

Dependence on imported oil increases the difficulty of predicting the basic parameters that define U.S. trade with other countries: the merchandise balance of trade, the direction of capital flows, and the value of the dollar relative to other currencies. Dependence on imported oil forces the U.S. economy (not just the global economy) to "recycle" petrodollars in some way -- to compensate for the direct effect of higher oil prices on the balance of trade. The adjustment mechanism is beyond the control of the United States, however; it is a source of economic uncertainty that defies modeling and forecasting.

In the short run, the U.S. economy responds to oil price increases by paying the higher price of imported oil rather than substantially cutting oil consumption. In the short run (up to a year), U.S. demand for oil is not very sensitive to oil prices. From 1985 to 1986, for example, the average amount of petroleum products supplied increased 2.5 percent while the average refiner acquisition cost of oil decreased about 45 percent.[61]

The direct effect of higher oil prices on the balance of trade is to increase U.S. imports, increase the current account deficit, and transfer dollars to foreigners. These dollars must be used by foreigners in some way in order to provide real payment for the oil. Claims against the U.S. economy must increase somehow. There are several ways the U.S. international transactions account can adjust to the higher price of oil:

- Reduce imports of goods other than petroleum
- Increase the volume of merchandise exports
- Increase prices of merchandise exports (e.g., to reflect higher energy costs of production)
- Reduce the rate of U.S. investment in foreign countries

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[61] See U.S. Department of Energy, Weekly Petroleum Status Report, February 20, 1987 DOE/EIA-0208(87-09), pp. 2, 17; Monthly Energy Review, October 1986, DOE/EIA-0035(86/10), pp. 36, 91.

- Increase the rate of foreign investment in the U.S.

One of the problems with oil import dependence in an era of price instability is that a sudden change in oil prices requires a sudden response of the international economic system, but it is difficult for governments and companies involved in international trade to prepare for this response. The following questions arise:

- What will OPEC nations do with the currency they receive in exchange for oil? Will they invest it in the developed nations or will they import goods and services? Will they buy U.S. goods or Japanese and European goods? Will they invest in the U.S. economy or other economies?

- Will OPEC continue to use dollars as the medium of payment for oil? If not, will an oil price increase cause the dollar to decline?

As these questions remain unanswered, oil import dependence increases the business risk associated with the trade balance and currency fluctuations. If OPEC nations use their income to invest in Wall Street, purchase American cars and appliances, and hire Bechtel, Fluor, and other U.S. firms to construct highways and buildings, the United States may ride out an oil price increase relatively well. If OPEC nations invest and spend their money elsewhere, the United States will have a more difficult time paying for oil imports.
Because the current account deficit has grown rapidly over the past three years, it is disturbing to realize that a sudden jump in oil prices could worsen the trade deficit. In this situation the flow of foreign capital into the U.S. compensates for a rise in oil prices. Because OPEC sets oil prices in dollars, the dollar may be strengthened by an oil price increase even though the U.S. merchandise trade balance may be adversely affected. With a strong dollar it becomes difficult for the U.S. economy to increase exports or reduce non-petroleum imports. As other oil importing countries try to increase exports to pay for higher oil costs, competition for export markets restricts the ability of U.S. producers to raise prices. On the other hand, the sudden transfer of purchasing power to oil exporting nations enables these nations to invest their dollars in the U.S. -- to purchase U.S. securities, assets, and real estate. Foreign investors may purchase U.S. securities in the hope that the dollar will be strengthened by other nations' need to pay dollars to OPEC nations. If oil-exporting nations purchase corporate debt or government debt issues, the U.S. effectively pays for a higher oil import bill by borrowing money.

One of the consequences of this increase in the trade deficit may be a reduction in the national saving rate -- a consequence which could adversely affect long term economic growth. Instead of sacrificing consumption of non-energy goods and services to pay for the increased cost of energy, Americans may sacrifice saving. Oil import dependence may lead, in other words, to foreign capital dependence. There is no guarantee that the flow of foreign capital will continue to finance domestic capital expenditures in the future.

The problem with this sort of response to oil price increases is that there would be a danger that saving would not recover when the price of oil falls. With a sharp reduction in "petrodollars" -- dollars received by oil-exporting nations for their oil -- the flow of foreign capital into the United States may not continue indefinitely. If reductions in this capital flow are not offset by increased saving, capital spending by U.S. companies could be seriously curtailed and U.S. economic growth would be reduced.

The danger of dependence on foreign capital inflows has been noted by the Council of Economic Advisors:

> It is important to recognize, however, that the development of the U.S. current account deficit has also been associated with a sharp drop in the national savings rate... To the extent that the drop in the national saving rate is not desirable, this dependence on net capital inflows to finance U.S. investment is also not desirable.[62]

It is possible that a sharp increase in oil prices would worsen the current account deficit and thereby lead to undesirable capital flows. This is only one illustration, however, of an adjustment process that could have an undesirable outcome for the U.S. economy.

CONCLUSION

Given the instability of oil prices and the adverse economic consequences of this instability, now is an appropriate time for the U.S. government to re-examine its policies toward oil exploration and production on non-Federal as well as Federal lands. Unnecessary impediments to oil exploration should be removed. Policy initiatives to encourage oil exploration in frontier areas, or to dampen the cyclical fluctuations in domestic exploration activity, need to be carefully considered.

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[62] U.S. Council of Economic Advisors, Economic Report of the President, January 1987, p. 112.

CHAPTER 2

ALTERNATIVE DEFINITIONS OF THE FEDERAL GOVERNMENT'S ROLE IN MANAGING OIL EXPLORATION ACTIVITY

The discussion in Chapter 1 has shown that the instability of crude oil prices adversely affects the U.S. economy, and the effects are significant because the magnitude of fluctuations in energy expenditure is large in relation to GNP. A cyclical, unstable pattern of oil prices will increase inflation, reduce the security of financial institutions, and increase the business risk associated with currency fluctuations; it may also increase unemployment and reduce labor productivity growth. When dependence on oil imports is added to the picture, there is an increase in inflationary pressure and in the business risk associated with currency fluctuations.

The source of these problems is the volatility of crude oil prices -- in particular, the increased volatility attributable to the fluctuating degree of OPEC's ability to influence the market, Saudi Arabia's ability to discipline OPEC, and the limited ability of non-OPEC nations to find and develop reserves that are economic when oil is priced at the competitive floor. The long-run marginal cost of oil still appears very low, at the global level -- perhaps $5 per barrel -- but OPEC nations control the bulk of the world's low-cost resources.[1]

Clearly the Federal government did not create the fundamental problem, and cannot remove it. The government cannot alter the global distribution of oil resources. Even if it were possible for the U.S. government to force OPEC nations to price oil at long-run marginal cost, the global distribution of petroleum resources could make the industrialized nations dependent on potentially unstable sources of supply. Although pricing oil at long-run marginal cost would achieve economic efficiency objectives and income distribution objectives,[2] it could exacerbate energy security problems. The decline in domestic exploration activity following the drop in oil prices in 1986 has sparked a concern, however, that the level of domestic oil exploration and production determined by market forces may be inadequate. To address this concern from the perspective of economic analysis it is necessary to ask why the response of the marketplace should be considered "inadequate." If it is cheaper to import foreign oil than extract our remaining domestic resources, why not pass the savings on to consumers and let our scarce resources be conserved for the future? What is the "problem" that appears to require government action?[3]

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[1] M.A. Adelman, "The Competitive Floor to World Oil Prices," The Energy Journal 7,4 (October 1986), p. 10.

Because there are costs to the U.S. economy associated with oil price instability, it is important to determine whether some form of government action is needed. The purpose of this chapter is to try to clarify the "problem" from the perspective of economic analysis and identify the kinds of actions the Federal government may take to resolve it. The conclusions of the chapter, briefly, are:

1. There exist both economic stability and market efficiency rationales for government action designed to mitigate the effects of oil price instability.

2. There are three levels of policy response the government could take:

    Level 1: Remove unnecessary impediments to oil and gas exploration.

    Level 2: Remove unnecessary impediments to oil and gas exploration and support exploration in frontier areas.

    Level 3: Remove unnecessary impediments to oil and gas exploration, support exploration in frontier areas, and dampen cyclical fluctuations in domestic oil exploration activity.

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[2] The World Bank has estimated that "if the price of oil fell from around $20-22 a barrel to $10-12 a barrel and stayed there for the next five years, the direct loss for oil-exporting developing countries (lost oil revenue) would outweigh the direct benefits for oil importers." The World Bank, World Development Report 1986 (New York: Oxford University Press, 1986), p. 50.

[3] This report is not intended to address national security issues or to duplicate the work of the Energy Security Working Group. National security is not a major responsibility of the Department of the Interior.

3. A choice among these options is in part dependent on political philosophies. The choice must be made on the basis of subjective judgments as well as on the basis of analysis.

The following discussion begins with a definition of the problems that the Federal government could address. After the problems are defined, policy options to resolve them are identified. For each of the three options cited above, a rationale for Federal action is presented. Finally, some of the considerations affecting the selection of an option are discussed.

IDENTIFICATION OF PROBLEMS THAT THE GOVERNMENT COULD ADDRESS

In broad terms the instability of oil prices is related to three kinds of concerns:

- Constraints on the U.S. economy that are completely beyond the government's control (e.g., the global distribution of petroleum resources)
- Economic problems that are best resolved by letting the competitive marketplace allocate resources (rather than having the government alter the allocation of resources)
- Economic problems that must be resolved by government actions because public interest benefits are not entirely reflected by competitive markets.

The focus of this chapter is on the last set of concerns. A presumption may be made that economic problems are best resolved by the marketplace unless there is evidence to the contrary -- evidence of some obstacle to an efficient allocation of resources. There are two basic rationales for government action to address the effects of oil price instability:

- The need to address economic stability problems -- to foster stable growth of the economy, including employment growth. The standard tools of economic stability policy are control of the money supply, adjustment of interest rates, adjustment of the Federal deficit, tax policy and measures designed to stabilize exchange rates.[4]

- The need to address market efficiency problems -- to remove obstacles to the achievement of an economically efficient allocation of resources.

The mix of economic stability and market efficiency concerns about oil supply makes it difficult to draw analogies between government policy toward oil exploration and government policy toward other industries. In the following discussion both sets of concerns are identified.

Economic stability issues

The framework for discussion of economic stability issues was established in Chapter 1. There are at least five activities the government could pursue to address the economic stability concerns outlined in Chapter 1:

- **Reducing dependence on oil imports** would reduce income transfers to oil-exporting nations; reduce the expected value of payments for imported oil that exceed the "avoided cost;"[5] reduce inflationary pressures; and reduce the business risk associated with currency fluctuations.

- **Reducing demand for petroleum products** would alleviate all of the concerns associated with the volatility of oil prices. Energy conservation and oil "backout" measures are included. This activity reduces the nation's reliance on oil but does not directly affect the nation's ability to rely on domestic rather than imported oil during a period of high oil prices.

- **Increasing the ability of end users to quickly switch to other energy sources when oil prices "peak"** would enable other fuels and energy sources to displace oil imports when necessary, and would yield the benefits associated with reduced dependence on oil imports. This activity reduces oil import dependence; it improves the nation's ability to reduce oil imports to a small share of energy consumption during a period of high oil prices.

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[4] Because national security has always been recognized as one of the government's responsibilities, the adverse effect of oil price instability on the nation's economic well-being could be regarded as a national security concern.

[5] The "avoided cost" is the exporter's long-run marginal cost.

- Increasing the ability of the domestic oil industry to increase production when oil prices "peak" would enable domestic resources to displace oil imports when necessary, and would yield the benefits associated with reduced dependence on oil imports, and yet postpone domestic production to the times when it is most needed. This activity may be regarded as a complement to the Strategic Petroleum Reserve, which permits a short-term "peak" in domestic crude oil receipts at refineries.

- Dampen the "boom and bust" cycle of domestic oil exploration. This activity would reduce the adjustment costs associated with moving labor and equipment in and out of the oil industry in response to oil price swings. The benefits of this activity would be reduced unemployment, increased labor productivity, increased security of financial institutions, and an increase in the ability of the domestic oil industry to raise production when oil prices "peak."

Although some of these measures, such as a reduction in import dependence, are often cited as reasonable objectives of Federal energy policy, the last two measures are cited less frequently. To ignore these measures would be a serious oversight, however. The second and third measures listed above are not a focus of this study because they are not a responsibility of the Department of the Interior.

Market efficiency issues

There are at least four areas of concern that might be used to define a rationale for government initiatives regarding oil supply:

- Unnecessary statutory and regulatory impediments to domestic oil and gas exploration may prevent resources from being allocated to oil exploration in a timely manner, and may prevent an efficient pattern of development. An example of a statutory impediment would be a full prohibition on access to exploration prospects in environmentally sensitive areas without regard to development benefits or the effectiveness of environmental mitigation measures. An "unnecessary" restriction may be defined as one that fails to achieve a reasonable balance between the cost to the nation of reduced oil exploration and production, and the intended benefits of the restriction (e.g., environmental protection benefits).

- Exploration in frontier areas is a "public good." The benefits of a new discovery in a frontier area include information that will help other firms find oil; information that will help identify the size of the domestic resource base; and information that will decrease the lead time needed to bring frontier resources into production in response to a price increase. These information benefits are not fully captured by the individual firm or joint venture funding the exploratory well. The marketplace does not appear to provide an adequate incentive, therefore, for exploration in frontier areas.[6]

The benefits of being able to respond to a price increase may be "undervalued" by the private sector because of the long-term nature of these benefits. It may be argued that the net present value of external benefits of exploration -- economic stability benefits associated with improvements in the nation's ability to respond to price increases -- should be discounted at a public sector discount rate rather than a private-sector discount rate.

- The threat of a crash in oil prices may create a tightness in capital markets that restricts exploration. To respond efficiently to a cyclical pattern of oil prices, oil companies need access to capital for which the investor assumes a risk, particularly over times frames shorter than a full price cycle. The investor must be willing to accept the risk that Saudi Arabia will occasionally discipline other OPEC members by dropping oil prices to the competitive floor, and the risk that the trough of an oil price cycle will last several years. If capital markets do not provide this financing, industry will be less able to make investments in oil exploration even when the benefits to the nation exceed the cost.[7]

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[6] If the information obtained from exploratory wells is not shared, firms collecting information to prepare competitive bids on lease tracts may drill two exploratory wells near the tract to be offered, where only one well would suffice. Although this effect may encourage "too much" exploration, the effect is likely to be minor. See Richard J. Gilbert and Joseph E. Stiglitz, Market Efficiency Associates, Effects of Risk on Prices and Quantities of Energy Supplies, EPRI EA-700 (Palo Alto, CA: EPRI, May 1978), Volume III, Chapter 1: "The Social and Private Value of Exploration Information."

The same divergence of private and public benefits that results in capital markets not allocating the socially optimale investment to oil exploration, may also discourage a wide variety of activities that alleviate the effects of oil price instability. The threat of an oil price crash deters investment in all activities that increase the short-run elasticity of crude oil supply, increase the short-run elasticity of petroleum product demand, or reduce petroleum product consumption (to protect the consumer against price increases).

Exploration is only one of the actions that increases the elasticity of crude oil supply. Domestic producers' response to price uncertainty may be to maintain "extra" acreage, "extra" reserves, and "extra" oil well production capacity as a hedge against oil price spikes. The oil well drilling industry may maintain "peaking" capacity. Hedges designed to capture rent in "peak" periods protect not only the individual firm but the nation as a whole, because they hedge domestic resources against oil imports.

- Under today's price expectations, Federal expenditures for energy development may be imbalanced. Frontier exploration is analogous to long-term, high-risk energy research and development (R&D). If the energy research and development budget were allocated across energy technologies on the basis of benefit/cost ratios, it may be appropriate to increase government support for oil exploration and reduce government support for technologies whose benefits are more speculative. Given the fact that the Federal government supports long-term, high-risk R&D in nuclear energy, renewable energy technologies, clean coal technologies, and enhanced oil recovery, support for frontier exploration may be a method of achieving an appropriate balance among energy

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[7] One of the responses of the marketplace to oil price risk is to protect investors against price decreases by raising the minimum acceptable rate of return for investments in oil exploration. This response is economically efficient and need not represent an imperfection; however, it does clearly identify a divergence between public and private goals. Such divergence may well signal a need for government action.

> technologies. Frontier oil exploration may be regarded as one of the components of long-term, high-risk energy investment.
>
> When oil prices and price expectations were high enough to stimulate private-sector investment in frontier exploration there was little or no need for Federal support. Under the new, lower price expectations, there may be significant divergence between public and private benefits associated with petroleum resource discoveries. Under lower price expectations there may be an imbalance among public-sector expenditures on energy development.

The foregoing list of market efficiency issues concerning the response of the marketplace to an unstable pattern of oil prices may not be complete. The problem of defining the efficient response of the economy to price instability created by a foreign cartel is not a simple problem with well-known solutions. Even if oil price instability were caused by random factors, rather than the actions of a cartel, the prerequisites for economic efficiency would be difficult to define.[8]

A normal response of the marketplace to price volatility is to diversify investment portfolios, including investments related to oil and gas if oil prices are unstable. Another response of the marketplace to oil price volatility is to diversify price risk by developing a price hedge. The crude oil and petroleum product futures market offers producers a hedging mechanism for the short term (e.g a period up to 6 months). Through a futures market the producer may obtain a more stable price for his oil.

In theory the United States could hedge against price uncertainty regarding imported oil through a long-term (e.g. 15-year) oil futures market with foreign participation and through long-term, enforceable contracts for oil imports at specified prices. To provide a hedge against long-term oil price fluctuations the United States would have to participate in futures contracts with oil exporting nations.[9] Only foreign producers have the reserve holdings necessary to guarantee delivery of oil sold under long-term futures contracts. U.S. experience with long-term liquefied natural gas contracts illustrates the difficulty, however, of enforcing the pricing clauses of long-term import contracts or futures contracts with OPEC nations. One reason that a long-term futures market does not exist is that there is no mechanism available to the private sector for enforcing the terms of such futures contracts.

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[8] See Richard J. Gilbert and Joseph E. Stiglitz, Market Efficiency Associates, Effects of Risk on Prices and Quantities of Energy Supplies, EPRI EA-700 (Palo Alto, CA: EPRI, May 1978), Volume II, Chapter 3, "General Equilibrium and Uncertainty," pp. 2.3-1 to 2.3-2.

OPTIONS AVAILABLE TO THE GOVERNMENT

To address the supply-related economic stability and market efficiency issues listed above, the government can choose among three policy options:

Level 1: Remove unnecessary impediments to oil and gas exploration.

Level 2: Remove unnecessary impediments to oil and gas exploration and support exploration in frontier areas.

Level 3: Remove unnecessary impediments to oil and gas exploration, support exploration in frontier areas, and dampen cyclical fluctuations in domestic oil exploration activity.

These levels of activity are stated in terms of broad objectives that define the focus of national energy policy, rather than specific actions that implement these objectives. Once a particular level is selected, it is necessary to evaluate a number of policy initiatives that might support that type of activity.

Level 1 defines the first step toward the development of a more efficient, more productive marketplace. Level 2 envisions a broader role for the government, and would extend to the oil industry the kind of support for long-term, high-risk projects that has historically been provided to the nuclear industry, to synfuels, and to renewable energy technology. Level 3 encompasses a still broader Federal role, in which the government adjusts its support for oil exploration on an annual basis in order to stabilize the performance of the U.S. economy.

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[9] To some extent U.S. interests might be protected by futures contracts or long-term contracts with non-OPEC producers such as Mexico, Canada, the United Kingdom, Norway, but this alternative fails to protect non-OPEC nations against OPEC manipulation of oil prices.

The three activity levels represent different selections from a group of three objectives and philosophies about the role of government:

- Remove unnecessary impediments to oil and gas exploration
- Support exploration in frontier areas
- Dampen cyclical fluctuations in domestic oil exploration activity.

The rationale for each objective is discussed below.

The rationale for removing unnecessary impediments to oil and gas exploration

The first step toward improving the vitality of the nation's oil and gas exploration industry is to remove the constraints associated with government regulations and restrictions that are needlessly inefficient, or that fail to achieve a reasonable balance between economic development objectives and other objectives. Unnecessary paperwork and permitting procedures can be modified or removed.

To identify unnecessary impediments to oil and gas exploration it will be necessary to re-examine Federal statutes and regulations that create impediments. The essence of this policy initiative is to force a re-examination -- to force agencies to spend resources on the review of the cost-effectiveness or reasonableness of regulations that would otherwise escape review. The intent of the initiative is to reveal situations in which statutes and regulations need to be changed.

The requirement to review the cost-effectiveness of regulations that impede oil and gas exploration is roughly comparable to a requirement that a regulatory impact analysis (RIA) be prepared for major new Federal regulations. While the preparation of an RIA need not cause a rule-making decision to be reversed, it provides some assurance that the new rule will be cost-effective. Similarly, the review of a particular regulation that impedes oil and gas exploration need not result in reversal of the regulation.

The rationale for supporting exploration in frontier areas

There are four basic arguments that can be used to show why the Federal government should provide incentives for oil exploration in frontier areas. These include three market efficiency arguments and one economic stability argument:

1. **Exploration in frontier areas is a "merit good."** The individual firm or consortium funding a new-field wildcat well cannot appropriate all the benefits of the exploration activity. Information about the petroleum geology of the area will help other firms decide whether to drill on adjacent tracts, and where. Information obtained from successful new-field wildcat wells improves the nation's ability to respond to an oil price increase by converting undiscovered resources into reserves. The discovery of new oil fields should increase the short-term elasticity of oil supply. Finally, information that helps to identify the size of the domestic resource base can make an important contribution to the development of energy policy.

   If the Federal government provides incentives for exploration in frontier areas, the program will fund exploration activity that would not occur until a much later time without government support. While such a program may appear to be "subsidizing uneconomic activity," in fact the program may promote economic efficiency. Government support is not really a "subsidy" but a payment for services received; it is comparable to government support for research and development (via cost-sharing or tax preferences). The incremental exploration activity is no more "uneconomic" than socially desirable investments in pollution control that would not exist in the absence of regulation. The label "uneconomic" is inappropriate because it suggests an activity that is wasteful and inefficient, rather than an activity that serves the public interest.

2. The threat of a crash in oil prices may create a tightness in the capital markets that restricts exploration, especially in high-cost or high-risk areas. Where expenditures are large and risky, private capital may have to be supplemented by government action. Because of the diversity of its "portfolio" of investments, the Federal government is in a better position to absorb large economic risks than private firms. The threat of a crash in oil prices is most likely to deter investments in areas in which the "breakeven" oil price is relatively high. The breakeven price associated with frontier areas is typically high because there may be a high risk of not finding oil, high drilling costs per foot, or both.

3. Under today's price expectations, Federal expenditures for energy development are imbalanced. The decline in oil price expectations since 1981 has made frontier oil exploration a long-term, high-risk energy investment deserving the same kind of support given to other energy technologies.

4. Frontier discoveries will increase the ability of the domestic oil industry to increase production when oil prices "peak." Improvements in the "peaking capacity" of the oil industry offer the economic stability benefits associated with reduced dependence on oil imports, and yet postpone domestic production to the times when it is most needed.

The fourth argument is not essential to the definition of the case for Federal support of frontier oil exploration. Even if one accepts the principle that economic stability concerns are not an acceptable basis for government action in particular sectors of the economy, it is possible to argue that incentives for frontier oil exploration are needed.

The rationale for dampening cyclical fluctuations in oil exploration activity

There are three arguments -- two economic stability arguments and one market efficiency argument -- in support of an active Federal role in dampening cyclical fluctuations in oil exploration activity:

1. **Supporting oil exploration during the trough of an oil price cycle will reduce our nation's dependence on oil imports.** Support for oil exploration during periods of low oil prices will probably raise annual reserve additions and will preserve the oil industry's capacity to increase domestic supply in response to high oil prices. The incremental reserve additions can be converted to production during high-price periods, when domestic resources are most needed. Maintenance of the industry's exploration and development capability will improve the industry's ability to raise production if the "peak" of the cycle lasts several years.

2. **Dampening the "boom and bust" cycle of domestic oil exploration would reduce the adjustment costs associated with moving labor and equipment in and out of the oil industry in response to oil price swings.** The benefits of stabilizing the level of exploration activity would be reduced unemployment, increased labor productivity, increased security of financial institutions, and an increase in the ability of the domestic oil industry to raise production when oil prices "peak." Given the painful adjustment of the oil industry and oil-producing states to the downturn in oil prices that occurred in 1986, concern may be expressed that our domestic energy industry is being whipsawed by foreign oil producers. While the loss of skilled manpower in the oil industry may be regarded as a reasonable reponse to today's prices, this loss may be regretted by the nation if the price of oil climbs sharply in the next few years. It may be argued that the government has a responsibility to stabilize oil exploration activity.[10]

   Oil exploration incentives could be considered an economic stabilization policy tool. Dampening oil exploration cycles may be regarded as a form of economic stability "fine tuning" comparable to controlling fluctuations in real interest rates.[11]

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[10] Similarly, all of the myriad adjustments of the economic system to lower energy price expectations may be reversed by the shifting politics of OPEC. It may be argued that petroleum product excise taxes should be raised when petroleum product prices are temporarily depressed by crude oil market conditions. However, the benefit of a fixed product exise tax, or import fee, is that it may be substantially shifted to the Foreign producers. The burden of a variable tarrif must fall entirely on the domestic consumer. Demand-side policy options are not examined in detail in this report, however.

Influencing oil exploration activity, to stabilize the cost of energy, is comparable to influencing interest rates, to alter the cost of capital. While income transfers are created by incentives for oil exploration, income transfers are also created by support for high real interest rates.

3. **Cyclical fluctuations in oil exploration activity may be exacerbated by capital market imperfections.** Investors' aversion to risk may cause investment decisions to be made on such a short-term basis that economically efficient investment opportunities are bypassed. In addition, investors' price expectations may be unduly influenced by recent events. During an oil boom, investors in the oil industry may be unreasonably optimistic about oil prices; during a bust, investors may be unreasonably pessimistic.

Unlike the case for Federal support of exploration in frontier areas, the case for dampening boom and bust cycles rests very heavily on economic stabilization issues.

SELECTING AN OPTION

The preceding analysis has defined the rationales for three different levels of activity:

Level 1: Remove unnecessary impediments to oil and gas exploration.

Level 2: Remove unnecessary impediments to oil and gas exploration and support exploration in frontier areas.

Level 3: Remove unnecessary impediments to oil and gas exploration, support exploration in frontier areas, and dampen cyclical fluctuations in domestic oil exploration activity.

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[11] The government's ability to stabilize the economy through fine tuning is debatable, of course. This argument is presented only to suggest that oil exploration incentives may be one of the policy tools involved in fine tuning the economy.

Level 1 reflects the narrowest definition of the proper role of the Federal government, while Level 3 reflects the broadest definition. While the potential weaknesses of the marketplace can be analyzed from the perspective of economic theory, a choice among political philosophies cannot be based upon economic analysis alone. Administration officials and members of Congress will bring to the issue their own philosophical outlook toward government, and their own understanding of its limitations.

Once a decision has been made to pursue a specific objective, such as support for exploration in frontier areas, the government should try to identify the least intrusive and least burdensome policy instrument. The Federal government seeks to:

- Avoid the use of special economic assistance programs for the oil industry that will only encourage other industries to lobby for special economic assistance
- Promote free trade among nations; avoid the use of protectionist policies that only encourage other nations to enact protectionist policies
- Limit the administrative cost and paperwork burden associated with government action in oil and gas markets; avoid a price support program that is equivalent to a Federal oil price control program
- Simplify the tax code; avoid the use of tax preferences that give special treatment to the oil industry and thereby encourage other industries to lobby for special treatment
- Enforce environmental regulations consistently; avoid the use of special waivers for the oil industry that will only encourage other industries to lobby for special treatment.

These concerns should be reflected in the government's choice of policy instruments.

There are several reasons why decision-makers may favor a narrow definition of the government's role. Because the Federal government's response to the 1973-1974 oil price shock was to impose an elaborate and unpopular system of price and allocation controls, both the oil industry and the public tend to be wary of any scheme for Federal action in the oil market. The enormous increase in the cost of agricultural commodity programs in the 1980s has reduced the popularity of price support and price stabilization programs as a mechanism to help U.S. producers compete in world markets. In addition, the public's experience with automobile import quotas has led to some disillusionment with government restraints on international trade.

On the other hand, political support for a laissez-faire philosophy toward energy markets has yet to survive an oil crisis. Over the last fifteen years, popular support for government involvement in energy markets has varied in direct proportion to the price of oil. The public's apparent reluctance to fund programs to reduce oil imports could vanish as soon as another oil price "shock" arrives.

In this political environment, one of the most constructive steps the government could take toward energy policy development would be to clarify the basic philosophy of government reflected in Federal energy programs.

CHAPTER 3

POLICY INITIATIVES DESIGNED TO REMOVE UNNECESSARY IMPEDIMENTS TO OIL EXPLORATION AND RESERVE CREATION

The first step toward improving the vitality of the nation's oil and gas exploration industry is to remove the constraints associated with government regulations and restrictions that are needlessly inefficient, or that fail to achieve a reasonable balance between economic development objectives and other objectives. Unnecessary paperwork and permitting procedures can be modified or removed.

To identify unnecessary impediments to oil and gas exploration it will be necessary to re-examine Federal statutes and regulations that create impediments to oil exploration and reserve creation. The essence of this policy initiative is to force a re-examination -- to force agencies to spend resources on the review of the cost-effectiveness or reasonableness of regulations that would otherwise escape review. The intent of the initiative is to reveal situations in which statutes and regulations need to be changed.

Once the government has reviewed an issue and made a decision (e.g., approved a land use plan that restricts oil and gas exploration in specific areas), decision-makers may be reluctant to re-open the issue even when new information and new circumstances suggest a reversal of the earlier decision. In the interest of removing impediments to oil exploration, however, controversial issues may need to be re-examined.

Regulatory impediments should not be confused with mechanisms by which the Federal government, as landowner, obtains a share of the economic rent associated with production from Federal lands. An impediment is a mechanism that reduces the economic attractiveness of a lease in a way that discourages exploration or production.[1] A rent capture mechanism must not be considered an impediment to exploration or reserve creation unless it affects the lessee's exploration, development, and production decisions. The collection of royalties, for example, is not an impediment, although the application of a unnecessarily high royalty rate to secondary or tertiary recovery may be an impediment. Competitive bidding on Federal leases is not an unnecessary impediment to exploration and reserve creation.

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[1] While the corporate income tax cannot be considered an "unnecessary impediment," because all companies are subject to income tax, it is possible for specific provisions of the tax code to create impediments by discriminating against oil production activity or against integrated oil firms.

In this chapter, regulatory impediments that affect oil exploration and reserve creation on Federal lands are reviewed. All but one of these impediments (the ban on export of Alaskan crude) directly involve the Department of the Interior's oil and gas leasing program. The phrase "exploration and reserve creation" is meant to encompass the process of maximizing recovery of oil in place (e.g., prolonging the productive life of a well) in addition to the process of identifying the location and geological environment of oil in place.

A number of measures could be implemented to encourage reserve creation through additional exploration and more complete recovery of existing "marginal" reserves. Specific measures that are recommended for further consideration include:

- Providing improved access to certain oil and gas exploration areas that may contain significant undiscovered recoverable resources. Areas for which improved access may be desirable include the California Outer Continental Shelf (OCS) and the Alaska National Wildlife Refuge.
- Repeal of oil and gas production diligence requirements for Federal leases. If some firms hold strong expectations about possible future increases in oil prices, this measure would permit those firms to explore and hold undeveloped reserves[2] in the expectation of higher oil prices. If such expectations materialize, both the firm and society will be better off for waiting. If such expectations do not materialize, the market can adjust expeditiously to call forth that production.
- Implementing a sliding scale royalty for Federal oil and gas leases that would scale from the currently applicable rate (typically one-eighth for onshore production

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[2] It may also be desirable to identify potential reserves that may be uneconomic at the prevailing level of oil prices, but could become economic at higher oil prices.

and one-sixth for offshore) to zero on low production rate wells. The aim of this measure would be to encourage more thorough recovery from economically marginal reserves.

- Reducing the minimum bid on Outer Continental Shelf leases from the current value of $150 per acre to the pre-1983 value of $25 per acre.
- Lifting the ban on export of crude oil from Alaska.

Each of these options is discussed below. The chapter concludes with a list of additional issues that are not directly related to Federal land management issues.

OPENING OF THE ARCTIC NATIONAL WILDLIFE REFUGE TO OIL EXPLORATION

Under this policy option the Federal government would provide access for oil firms to explore and develop certain Federal lands -- the coastal plain of the Arctic National Wildlife Refuge (ANWR) in Alaska -- that have significant petroleum resource potential. Oil resources on the ANWR in Alaska cannot be explored and developed because of statutory restrictions on access. At present, land use restrictions under the wildlife refuge designation established by Congress prevent leasing, exploration and development in the ANWR.

The ANWR is located in northern Alaska between Prudhoe Bay and and the Canadian border. The area proposed for oil and gas development is the coastal plain of ANWR, which represents less than 20 percent of the total area of ANWR. In the context of Congressional debate this area is also known as the 1002 area.

The oil resources of the coastal plain of ANWR could be very large. DOI estimates that there is a 95 percent probability that the coastal plain of the ANWR contains at least 4.8 billion barrels of oil and 11.5 trillion cubic feet of natural gas. Oil reserve additions of this magnitude would be equivalent to roughly half the 1970 reserve additions of Prudhoe Bay and roughly 68 percent of the proved crude oil reserves of Alaska at December 31, 1985.[3] The odds of discovering a giant oil field are relatively good; DOI estimates indicate a 5 percent probability that the ANWR coastal plain contains at least 29.4 billion barrels of oil and 64.5 trillion cubic feet of natural gas. Among U.S. frontier regions, ANWR appears to offer the best prospects for discovery of a giant oil field.

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[3] U.S. Department of Energy, Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1985 Annual Report, DOE/EIA-0216(85), p. 22

Although activity in ANWR is very costly, industry may move vigorously here because of the substantial resource potential.[4] Because ANWR is close to Prudhoe Bay, no additional trans-Alaska pipeline would be required to move ANWR oil to Valdez, the terminus of the present pipeline.

Providing access to these promising areas could lead to significant improvement in the United States' deteriorating reserve position. Although there may be long (10- to 15-year) lead times associated with exploration and development of ANWR's oil resources, a major reserve discovery would improve the ability of the United States to increase domestic production in response to oil price increases in the mid to late 1990s. ANWR might provide a significant addition to non-OPEC oil production and thereby dampen world oil prices in the 1990s, just as North Sea production dampened oil prices in the mid 1980s.

Proposals to provide access to the coastal plain of ANWR face political obstacles, however. Providing access to ANWR will require overcoming the objections of environmental organizations and some Alaskan groups who oppose any change in the current ANWR land use restrictions. The coastal plain is the breeding ground of a caribou herd, and some environmental organizations are concerned about the impact of oil and gas development on the caribou. To establish the future of ANWR Congress will have to weigh energy supply objectives against other land use objectives.

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[4] Activity in ANWR would no doubt accelerate if expanded access were coupled with some form of drilling incentive provided by the Federal government.

OPENING OF THE CALIFORNIA OUTER CONTINENTAL SHELF TO OIL EXPLORATION

Another policy option related to Federal land access is to allow firms to explore and develop the portions of the California OCS that are now closed to oil exploration. A Federally legislated leasing moratorium prevented new leasing on the California OCS. Despite considerable effort in recent years in negotiations between DOI officials and California congressional representatives, a compromise has not been able to be reached that would permit leasing, exploration and development on the California OCS.

Because of its relatively benign operating environment, exploration on the California OCS might occur relatively vigorously even at today's prices. The Department of the Interior (DOI) estimates that the expected value of undiscovered economically recoverable resources for the California OCS is 1.82 billion barrels of oil equivalent. The growth of California OCS reserves over the last decade stands in sharp contrast to the reserve changes in other major oil-producing areas such as Texas, Louisiana, Alaska, and onshore California (see Exhibit 3.a).

Previous efforts at negotiation have failed to yield a satisfactory resolution of the California OCS controversy and the new California congressional delegation has already indicated its intent to strengthen the existing limitations on Federal leasing activity.

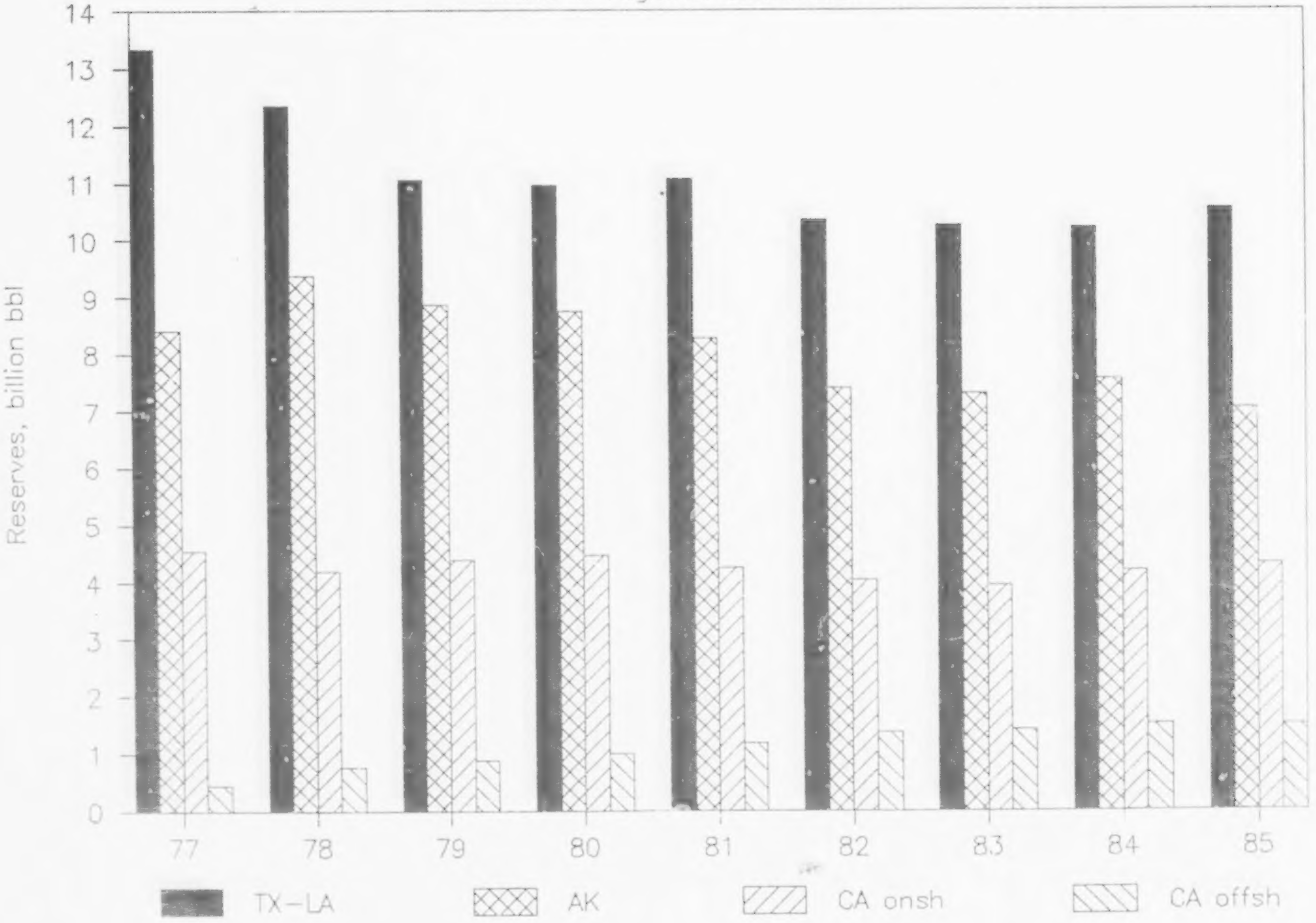
REPEAL OF PRODUCTION DILIGENCE REGULATIONS ON FEDERAL OIL AND GAS LEASES

Currently, Federal oil and gas leases are subject to production diligence requirements as well as exploration diligence requirements. Removal of the production requirement would allow lessees, it they so desired, to delay production from discoveries in the expectation of higher prices. Such delays in production could be advantageous because firms could improve their ability to increase domestic production in the "peak" of an oil price cycle without raising production during the "trough" of the cycle. In other words, relaxation of production diligence regulations would probably increase the elasticity of domestic oil supply. Removal of production diligence requirements would be a relatively costless incentive to implement.

Exhibit 3.a

Crude oil proved reserves

Trend in regional distribution



Production diligence requirements for Federal oil and gas leases provide little if any economic efficiency benefits. Essentially, they prevent firms from delaying or slowing down production activity in response to private market pricing information. Proferred justifications for diligent production requirements include:

- Preventing collusion among firms to delay production and drive up prices;
- Eliminating production timing problems that might result from a difference in public and private sector discount rates;
- Offsetting other problems of different social and private costs that might cause firms to inefficiently delay production;
- Encouraging firms not to take leases unless they are seriously interested in near-term development;
- Legitimizing the governments planning process;
- Preventing full, perpetual transfer of development rights (equivalent to a sale rather than a lease);
- Allowing government to periodically reconsider and charge prior land use decisions by fiat; and
- Helping govenment capture speculative profits, when used in conjunction with appropriate minimum bid requirements.

In general, there is at best tenuous validity to any of these concerns and, hence, little basis in economic efficiency for diligent production requirements. In any events, a holding fee or minimum royalty, properly set, would permit a proper market solution, rather than the more-or-less arbitrary results detained by the current approach through government fiat.

A possible misunderstanding concerning production diligence requirements is that they protect the Federal government's interests by discouraging speculation in reserves. In fact, speculation in oil reserves -- the practice of holding reserves in anticipation of price increases -- provides a valuable contribution to energy security at a time when oil prices appear to be in the "trough" of a price cycle. It may be in the national interest to identify reserves but delay production from those reserves.

A problem with diligent production requirements is that they may prevent firms from responding individually to diverse expectations regarding future resource scarcity and the associated paths of energy prices. Diligent production requirements may prevent those firms that are more pessimistic about future energy resource scarcity from conserving oil and gas reserves for production during a time of greater demand (relative to supply). In this way, diligent production requirements may contribute to efficiency losses by preventing firms from providing a hedge against future resource scarcity.

In today's oil market, production diligence requirements may cause firms to produce "now" when the additional domestic production has little incremental value to society, and prevent firms from delaying production until a time (perhaps only a few years away) when the marginal benefit to society from the production could be substantially greater. Some firms with adequate financial resources may choose to explore now for oil and gas to take advantage of low exploration costs (e.g., low acreage acquisition costs, low day rates for drilling rigs). In addition, these firms may expect generally higher oil prices in the future. If these firms discover oil and gas on Federal leases, the production diligence requirements would cause them to begin production. However, these firms may prefer to wait to produce at a time when they believe demand will be greater (relative to supply) and when their return from development and production would therefore be greater (taking account of the time value of money).

Production diligence requirements could also cause firms to forgo the opportunity to explore and discover the resources now because of the recognition of the requirement for timely -- but perhaps uneconomical -- production. Particularly in frontier areas, where discovery of a small field may not justify infrastructure development prior to additional discoveries. In this situation diligence requirements discourage exploration and worsen the nation's oil reserve position.

Simulation analyses of development and production timing decisions under alternative price paths show that firms could benefit by holding reserves for later development and production under reasonably plausible price expectations. Specifically, using the current DOE/EIA mid-range price projection, an analysis of development and production decisions for typical onshore, lower-48 discoveries showed that firms might reasonably delay production by up to three years. This price projection assumes an annual average price of $14 in 1986, increasing to an annual average of about $18.50-$19.00 (constant 1986 dollars) by 1990, and to about $35.00 (constant 1986 dollars) in 2000. If firms attach a high probability to price increase scenarios such as this one, firms may be willing to explore **now** with the expectation of delaying production.[5]

If firms foresee a somewhat more abrupt price escalation scenario, then the advantage of delaying production increases. Specifically, analyses were performed of a scenario in which prices grow at an average real rate of 1.0 percent for 5 years, jump by 50 percent in the sixth year (1992), and then grow at an average real rate of 8 percent annually. In this case, the price in 1990 (constant 1986 dollars) was about $15.50, in 1995, about $29.50, and in 2000, about $43.00. In this case, the advantage of delaying development and production of a discovery increases, with delays of up to 10 years sometimes being beneficial to the exploring firm. This price scenario is highly specific and might not be the type of expectation on which firms would risk substantial monies. However, the indicated range of price increases is not implausible; given the regulatory freedom to do so, firms might willingly commit a part of their reserve portfolio to future production on the prospect of substantially higher production prices.

Removal of production diligence requirements would permit firms to hold greater oil and gas reserves on the expectation of higher future oil prices. Whether firms would indeed act in this manner is uncertain. The removal of production diligence requirements may not be an effective method of stimulating exploration; although it would remove an impediment. The cost of removing the requirement is very low and the possible benefit could be significant. Whether or not holding fees or minimum royalties should be enacted requires further analysis beyond what is provided here.

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[5] This exploration activity may be impeded by capital market imperfections, however.

IMPLEMENTATION OF A "ZERO-BASED" ROYALTY FOR MARGINAL PRODUCTION ON FEDERAL LANDS

Currently, the usual fixed (and minimum, in the case of a sliding scale schedule) royalty rates applying to Federal oil and gas leases are one-sixth for OCS production and one-eighth for onshore production. Under the "zero-based" royalty incentive, a sliding scale royalty schedule would be adopted for so-called marginal production that would extend from the current one-sixth or one-eighth to zero. For example, a possible zero-based royalty schedule might extend downward from the current minimum onshore rate of one-eighth as the daily production rate per well declined from 30 barrels per day to 5 barrels per day. This incentive is not aimed at creating new reserves by encouraging exploration; instead, it is aimed at increasing ultimate recovery from currently producing reservoirs and thereby effectively enlarging the reserve base that is currently in production.

A royalty is applied to oil and gas production from Federal leases as part of the process of collecting a return to the public from the transfer of mineral resource rights to the private sector. Although royalties are an accepted means of providing a return to the owner of mineral resource rights, it is also recognized that a royalty can interfere with the efficiency of resource recovery by increasing the production cost burden. In effect, a royalty reduces the price received by the lessee in producing oil and gas from a lease. As a result, some resources may not be recovered from a lease that would otherwise be economically producible with a lower or no royalty.

A substantial portion of oil production on Federal lands occurs at low daily production rates from "stripper" wells and other marginal operations. At low oil prices, there is an increased risk that these wells may be shut-in or abandoned, leaving technically recoverable resources unproduced, perhaps forever. A zero-based sliding scale royalty rate may be able to offset some of this resource loss by reducing the cost burden on such marginal resources.

Simulation analyses of marginal production cases suggest that a zero-based royalty can extend recovery from currently marginal oil and gas production activities. However, use of a zero-based royalty will almost certainly mean lower Federal royalty revenues, as it would be impossible to restrict the lowering of royalties to only that production that requires a lower royalty to remain economic. Although the economic efficiency effects of this measure are beneficial, the measure would likely result in lower Federal royalty collections.

REDUCTION OF OCS MINIMUM BID REQUIREMENTS

A possible approach to increasing bidding and exploration interest for Federal OCS acreage would be to reduce the minimum bid. To the extent that firms are willing to bid for and explore acreage whose assessed bid value is positive but less than the minimum bid, a reduction in the minimum bid would enlarge the number of tracts that firms may acquire and explore.

Since 1983, the minimum bid required for OCS leases has been $150 per acre. Previously, the Department of the Interior had set a minimum bid level of $25 per acre. At the minimum bid of $150 per acre, a bidder must offer a minimum of $864,000 for the typical 5760-acre tract. At the previous minimum bid level of $25 per acre, the minimum bid for a standard tract was $144,000.

Analyses by the Minerals Management Service show that, in today's oil price environment, returning the minimum bid to its former level of $25 per acre could increase the number of leases bid on and awarded by as much as 75 percent for lease sales in the Gulf of Mexico. Although the average high bid per acre received would be expected to decline, the total bonus bid receipts could increase.

The success of this option in increasing exploration and reserve creation activity will depend on the ability of firms to finance additional activity. If firms remain cash-constrained because of low oil prices, a reduction in the minimum bid may have little effect in encouraging additional exploration and reserve creation activity.

The success of this option will also depend on whether firms will explore the acreage acquired at the lower bid prices, rather than hold it for speculation on acreage. The less prospective acreage leased at lower minimum bid values may not actually be drilled any earlier than would occur if it were leased at a later date (following successful activity nearby) at a higher minimum bid price. A strategy frequently followed in the past, for example, was for smaller firms to acquire marginally prospective acreage at low bid values (near the minimum bid). Such acreage might lie adjacent to more promising acreage that would typically be leased at much higher bid levels and explored by larger firms. Subsequently, the lessees that acquired the marginally prospective acreage would only drill this acreage if drilling on the more promising acreage proved successful.

REMOVAL OF THE BAN ON EXPORTS OF ALASKAN CRUDE OIL

Another policy option that would stimulate domestic oil exploration and reserve creation would be a lifting of the ban on exports of Alaskan crude oil. Section 20 of the Merchant Marine Act of 1920 (the Jones Act) requires carriage of Alaskan crude oil by U.S. flag tankers between U.S. ports. This statutory provision prevents Alaskan crude from being shipped to Japan and other Pacific Rim countries. Roughly half the current production of northern Alaskan oil is shipped to Caribbean and Gulf Cost ports via the Panama Canal.[6]

A policy of lifting the ban on exports of Alaskan crude oil offers both advantages and disadvantages regarding the nation's ability to cope with oil price instability.

The advantage of lifting the ban on exports is that it should increase domestic reserves and production capacity. Because it is less expensive to ship oil to Pacific Rim countries rather than to U.S. ports, the netback value of northern Alaskan crude oil -- the wellhead price at which northern Alaskan oil is competitive with other sources of crude-- will be raised when the ban on exports is lifted. Wellhead prices of Alaskan crude should therefore increase, and the price increase should stimulate exploration activity. With increased exploration there should be an increase in reserves and production capacity. It also would tend to reduce or eliminate the West Coast price discount and thus make other energy investments more attractive.

The increase in reserves and production capacity has three benefits:

1. If the price of oil rises sharply, U.S. production will increase and U.S. producers will thereby capture economic rents during the peak of an oil price cycle. The nation's ability to capture

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[6] For a discussion of this issue see U.S. Department of Energy, Energy Security. A Report to the President of the United States (Washington, D.C., March 1987), pp. 89-90.

economic rents during boom times is related to the level of net imports, not the level of imports. If net imports drop sharply when the price of oil rises, the price-induced income transfer to other oil-exporting nations will be moderated.

2. In an emergency, the nation will benefit from having the additional production capacity and reserves attributable to the lifting of the ban. If an oil crisis dictates a need to divert northern Alaskan oil from the export market to the domestic market, there will probably be no economic obstacles to rerouting shipments. Because crude oil is generally sold on a "spot" basis, it is unlikely that the terms of U.S. crude oil export contracts would commit producers to oil exports on a long-term basis; if necessary, Congress could prohibit long-term export contracts.

3. An increase in non-OPEC (Alaskan) oil production capacity will make a modest contribution to restraining global oil price increases. Every addition to non-OPEC capacity is helpful. The combined effect of comparable contributions to non-OPEC supply may be large, even if the individual contributions are modest.

The principal disadvantage associated with lifting the export ban is that production of oil for export, like production of crude oil for domestic consumption, tends to deplete U.S. resources of oil. Resources that are produced and exported will not be available for future generations to rely upon if oil prices rise dramatically. Lifting the export ban creates an incentive to increase production as well as exploration.[7]

An issue to be resolved by the political process is the question whether concerns about the depletion of our Alaskan oil resources outweigh the advantages associated with an increase in reserves and production capacity.

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[7] In theory a short-term stimulus to exploration alone might be created by an announcement that the ban will be lifted at some future date, such as 1995. Because the political decision is so easily reversed, however, such an announcement may have no material effect on firms' expectations regarding the wellhead price of Alaskan oil, and no effect on exploration activity.

INITIATIVES UNRELATED TO FEDERAL LAND MANAGEMENT

A comprehensive review designed to identify unnecessary impediments to oil exploration and reserve creation should include the following topics, in addition to those listed above:

- Decontrol of wellhead prices of natural gas. Analysis of this issue is largely the responsibility of the Federal Energy Regulatory Commission, subject to the requirements of the Natural Gas Policy Act of 1978.[8]

- Relaxation of regulation of pipeline rates, where gas-on-gas competition prevents the exercise of monopoly power by interstate pipelines. Analysis of this issue is also the responsibility of the Federal Energy Regulatory Commission.[9]

- Repeal of the Windfall Profits Tax. Analysis of proposed revisions in the tax law is largely the responsibility of the Department of the Treasury.[10]

- Repeal of the prohibition on land disposal of certain oil production wastes. The 1984 amendments to the Solid Waste Disposal Act prohibit disposal of certain oil production wastes via spreading on soil or injection into the ground. Where small quantities of waste are involved, the cost-effectiveness of these regulations may be reviewed by the Environmental Protection Agency.[11]

These issues are not analyzed in this chapter because none of them is directly related to Federal land management issues. Regulatory authority regarding these issues does not reside with the Department of the Interior.

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[8] See U.S. Department of Energy, Energy Security, p. 126.

[9] For those routes and those classes of service in which pipeline rates are restrained by competition, economic theory suggests that deregulation is appropriate. Requirements for pipelines to charge non-discriminatory rates should not be confused with deregulation.

[10] See U.S. Department of Energy, Energy Security, p. 75.

[11] See U.S. Department of Energy, Energy Security, p. 65.

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CONCLUSION

Although oil price and allocation controls have been lifted, the industry still faces impediments to exploration and reserve creation that create economic efficiency losses. A reasonable policy objective is to examine the need for such impediments and discard those that prove unnecessary. At present there are at least six things the government can do to remove impediments to oil exploration and reserve creation activity on Federal lands:

- Open the Arctic National Wildlife Refuge to oil exploration
- Open the California Outer Continental Shelf to oil exploration
- Repeal production diligence regulations on Federal oil and gas leases
- Implement a "zero-based" sliding scale royalty for marginal production on federal lands
- Reduce OCS minimum bid requirements
- Remove the ban on exports of Alaskan crude oil.

A careful review of the advantages and disadvantages of these options is needed to guide public policy decisions.

CHAPTER 4

POLICY INITIATIVES DESIGNED TO PROMOTE EXPLORATION IN FRONTIER AREAS

In addition to removing impediments to oil exploration the Federal government may choose to take an active role to support frontier exploration, just as it has taken an active role in supporting research and development of other energy technologies that offer long-term benefits to the nation. In this chapter the various rationales for supporting frontier exploration are reviewed. Considerations in designing and analyzing incentives are discussed from the standpoint of economic efficiency and cost-effectiveness. Two groups of policy initiatives are examined: those that are compatible with DOI's existing mandate to manage Federal oil and gas resources, and those that either extend the program to non-Federal lands or reduce the Federal budget impact of an exploration support program.

THE RATIONALE FOR PROMOTING EXPLORATION IN FRONTIER AREAS

Policy initiatives designed to promote exploration in frontier areas should be seriously considered for four reasons:

1. **Exploration in frontier areas is a "public good."** The individual firm or consortium funding a new-field wildcat well cannot appropriate all the benefits of the exploration activity. Information about the petroleum geology of the area will help other firms decide whether to drill on adjacent tracts, and where. Information obtained from successful new-field wildcat wells improves the nation's ability to respond to an oil price increase by converting undiscovered resources into reserves. The discovery of new oil fields should increase the short-term elasticity of oil supply. Finally, information that helps to identify the size of the domestic resource base can make an important contribution to the development of energy policy.

2. **The threat of a crash in oil prices may create a tightness in the capital markets that restricts exploration, especially in high-cost or high-risk areas.** Where expenditures are large and risky, private capital may have to be supplemented by government intervention. Because of the diversity of its "portfolio" of investments, the Federal government is in a better position to absorb large economic risks than private firms. The threat of a crash in oil prices is most likely to deter investments in areas in which the "breakeven" oil price is relatively high. The breakeven price associated with frontier areas is typically high because there may be a high risk of not finding oil, high drilling costs per foot, or both.

3. **Under today's price expectations, Federal expenditures for energy development are imbalanced.** The decline in oil price expectations since 1981 has made frontier oil exploration a long-term, high-risk energy investment that may deserve the same kind of support given to other energy technologies.

4. **Frontier discoveries will increase the ability of the domestic oil industry to increase production when oil prices "peak."** Improvements in the "peaking capacity" of the oil industry offer the economic stability benefits associated with reduced dependence on oil imports, and postpone domestic production to the times when it is most needed.

There are two reasons why a focus upon frontier areas is important. First, the divergence between public and private benefits of exploration is likely to be greatest in frontier areas. It is necessary to encourage exploration in those areas with greater potential for significant new discoveries and greater value in providing information for policy-making. Second, by encouraging firms to explore in these higher risk, frontier areas that they would now otherwise likely ignore, there is a greater likelihood that the exploration incentive will apply to new, incremental activity instead of exploration that would have been undertaken in any event.

Returns on the Federal government's investment in frontier oil exploration

The Federal government must play a dual role in policy initiatives concerning exploration. As a guardian of the public interest, the government can espouse the arguments cited above without regard to the identity of the parties who will capture economic rents during the "peak" of an oil price cycle. As landowner and tax collector, however, the government must take an interest in capturing rents for itself. The Federal budget impact of policy incentives to promote exploration will be affected by the government's ability to capture the social benefits cited above:

- If local information externalities are valued highly by the marketplace, the cost to the government of the exploration support program will be offset by an increase in bonus payments received on tracts adjacent to those enjoying exploration cost sharing. By promoting exploration the government will increase the market value of frontier tracts it will lease in the future, even if those tracts no longer qualify for exploration incentives when they are auctioned.

- If an exploration incentive program improves economic efficiency by correcting for information externalities, it should increase the GNP (if only slightly). Federal tax receipts will increase as the GNP increases. Through the tax system the government captures a portion of the value of an information externality when that information is used to generate taxable income.

- If capital market imperfections are offset by an exploration incentive program, economic efficiency is improved. As above, the GNP should increase and therefore tax receipts should increase.

- If an exploration incentive improves the ability of firms to increase production on Federal lands during the peak of an oil price cycle, without increasing production during the trough of the cycle, the present value of government royalty revenue will increase. The "investment" in the incentive program will pay off in the form of higher royalties (and higher tax receipts) in boom times.

- If an exploration incentive leads to increased production on Federal lands during the peak of an oil price cycle, less income will be transferred to oil-exporting nations during the price "peak." The GNP will therefore increase. With a smaller income transfer to oil-exporting nations, there will be less inflationary pressure on the U.S. economy.

While the magnitude of these effects is difficult to quantify, it is important to recognize that a program to support frontier exploration, like an economic development program, may turn out to be a reasonable "investment" from a Federal budget standpoint as well as an economic efficiency standpoint.

CONSIDERATIONS IN DESIGNING AND ANALYZING INCENTIVES TO ENCOURAGE EXPLORATION

Incentives to encourage additional exploration activity and, ultimately, reserve creation, must address two problems:

- At petroleum prices around $15 per barrel, the component of the undiscovered, recoverable resource base that appears economic to explore has declined considerably relative to the level that would have been attractive a few years ago at higher oil prices. Undiscovered, recoverable OCS resources in the Gulf of Mexico, Alaska, Atlantic, and Pacific are particularly sensitive to oil price levels below $15 per barrel (see Exhibit 4.a). As a consequence, exploration activity has virtually halted in some of the more prospective resource areas on the OCS and in the Overthrust Belt. Thus, a successful initiative to increase exploration and reserve creation must increase the apparent economic return that oil companies may expect as they contemplate exploration and development in these areas, or decrease the risk associated with exploration in these areas.

- At currently depressed petroleum prices, many firms have little financial capability to mount additional significant exploration activity. Historically, expenditures for exploration have moved with cash flow from operations. While drilling costs have declined substantially, oil industry costs have not fallen as rapidly as prices with the result being deteriorated financial performance and cash flow in the industry (see Exhibits 4.b, 4.c, and 4.d). The problem of declining prices and shrinking cash flow is exacerbated by the financial restructuring of the industry that has occurred over the last five years -- oil firms have taken on significantly more debt and hence, fixed charges, than was tradition-

Exhibit 4.a

Undiscovered Economically Recoverable

OCS Resources by Price

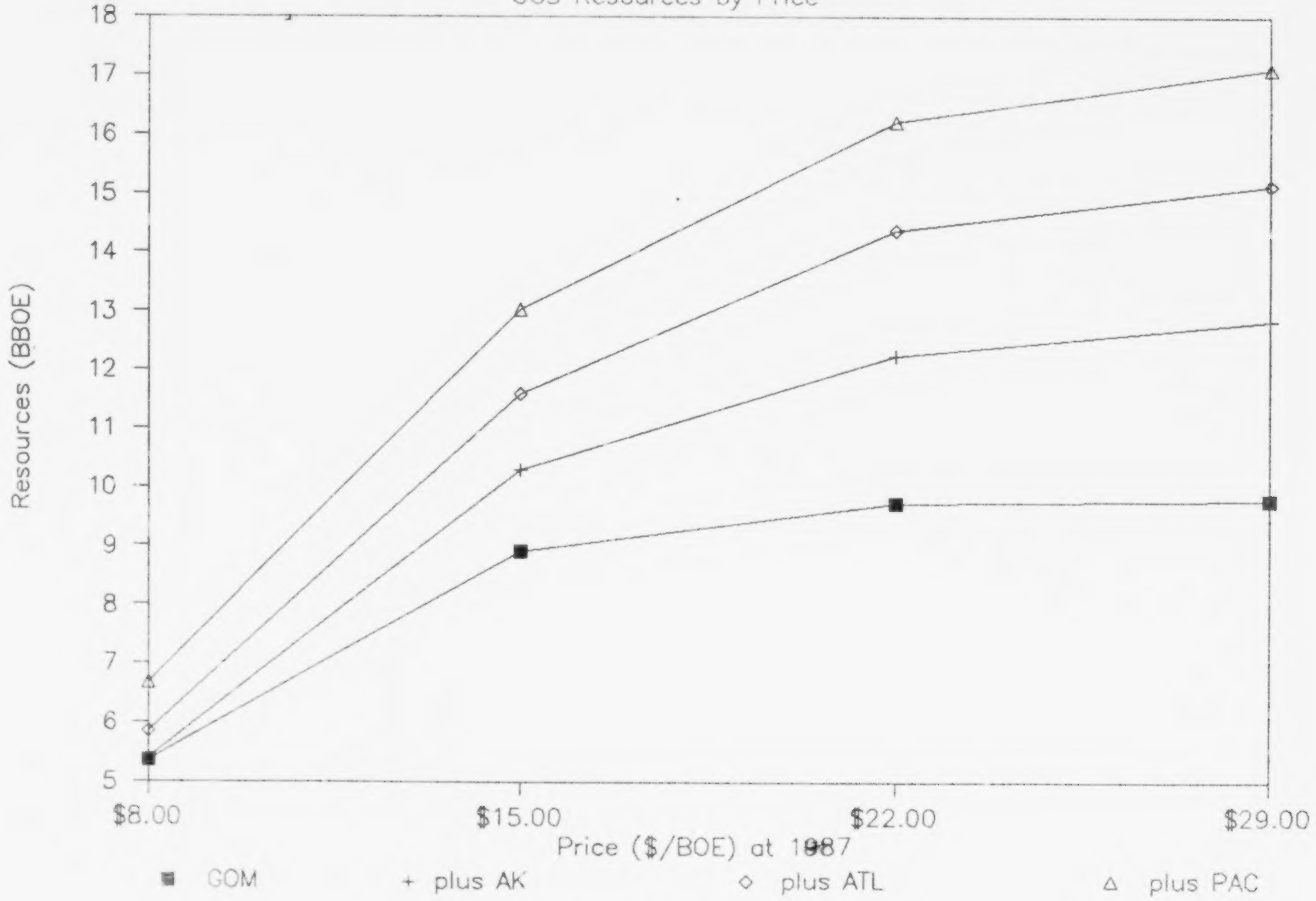


Exhibit 4.b

Measures of Financial Performance and Health of Integrated and Independent Oil Producers, 1981-1986

(All dollar values are in millions of 1986 dollars.)

	1981	1982	1983	1984	1985	1986
Financial Performance of 27 Integrated Producers						
Net Profit	38523.4	24538.4	24950.3	25295.5	25093.3	15000.0
Depreciation	25900.9	23168.8	25170.2	27412.2	31750.7	33000.0
Cash from Operations	64424.3	47707.3	50120.5	52707.7	56843.9	48000.0
Working Capital	56231.0	29103.7	32424.4	17780.9	13314.8	15000.0
Long-Term Debt	84953.6	69392.4	66387.7	38587.0	82961.4	78000.0
Net Worth	228917.8	196079.2	197514.3	189133.8	172785.1	172000.0
Debt/Net Worth	37.11%	35.39%	33.61%	46.84%	48.01%	45.35%
Financial Performance of 17 Independent Producers						
Net Profit	537.6	341.3	167.6	232.3	122.5	-10.0
Depreciation	642.2	547.5	579.2	659.6	674.3	620.0
Cash from Operations	1179.8	888.7	746.9	891.9	796.8	610.0
Working Capital	582.7	215.0	134.6	26.6	111.1	80.0
Long-Term Debt	3700.7	2680.3	2596.6	2231.0	2285.0	2600.0
Net Worth	3786.8	2729.7	2169.5	2140.7	2244.8	2025.0
Debt/Net Worth	97.73%	98.19%	119.69%	104.22%	101.79%	128.40%

Source of financial data: The Value Line Investment Survey, Value Line, Inc., New York, N.Y. Issue of October 10, 1986, pages 401-429; issue of December 12, 1986, pages 1830-1847.

Data for 1986 are Value Line estimates.

All dollar values have been converted to 1986 constant dollars using the implicit GNP deflator series as published in the Survey of Current Business by the Bureau of Economic Analysis, U.S. Department of Commerce. The 1986 deflator value was estimated as an average of the published values for the first three quarters of 1986.

Exhibit 4.c

Financial Performance Measures

27 Integrated Producers

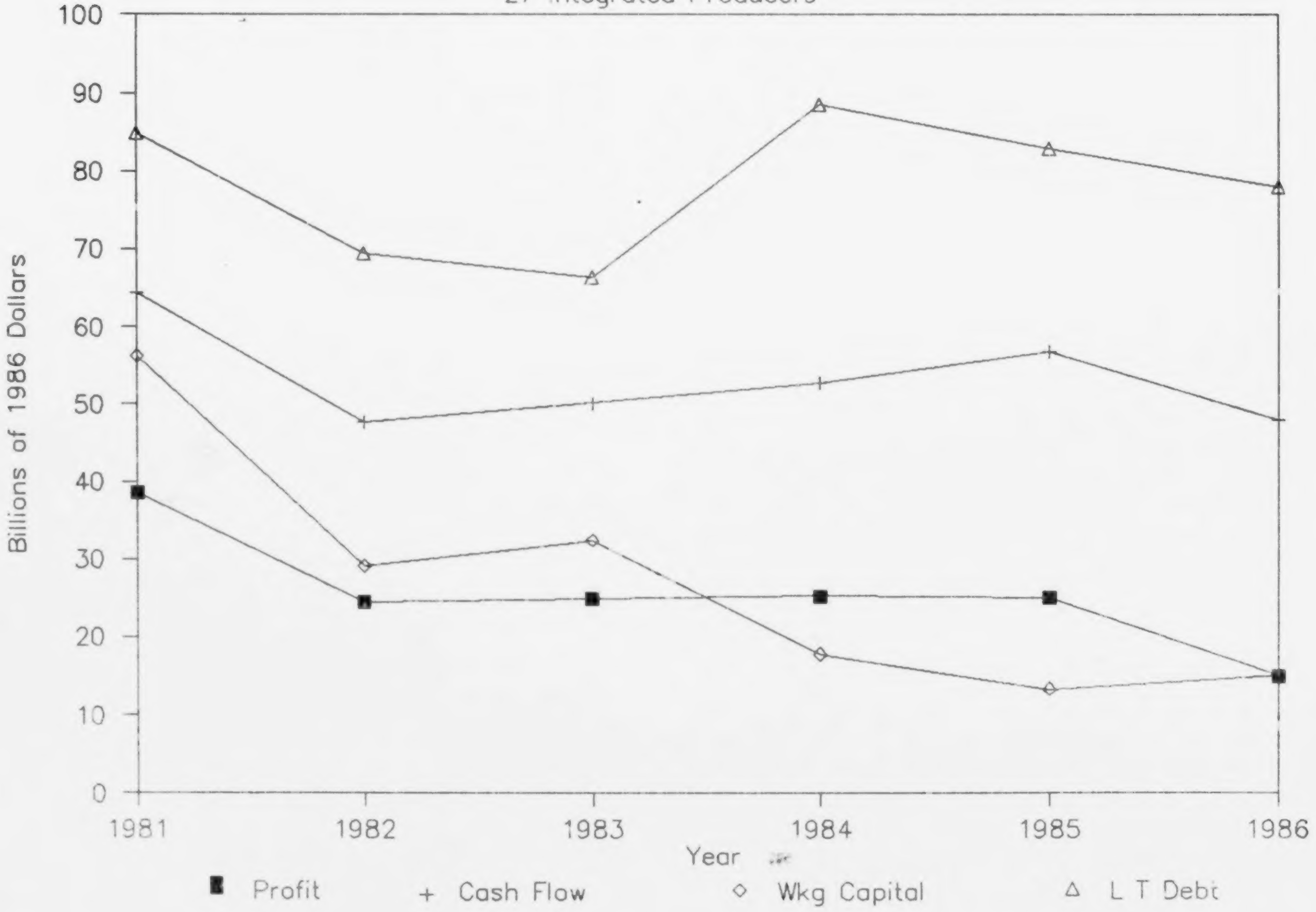
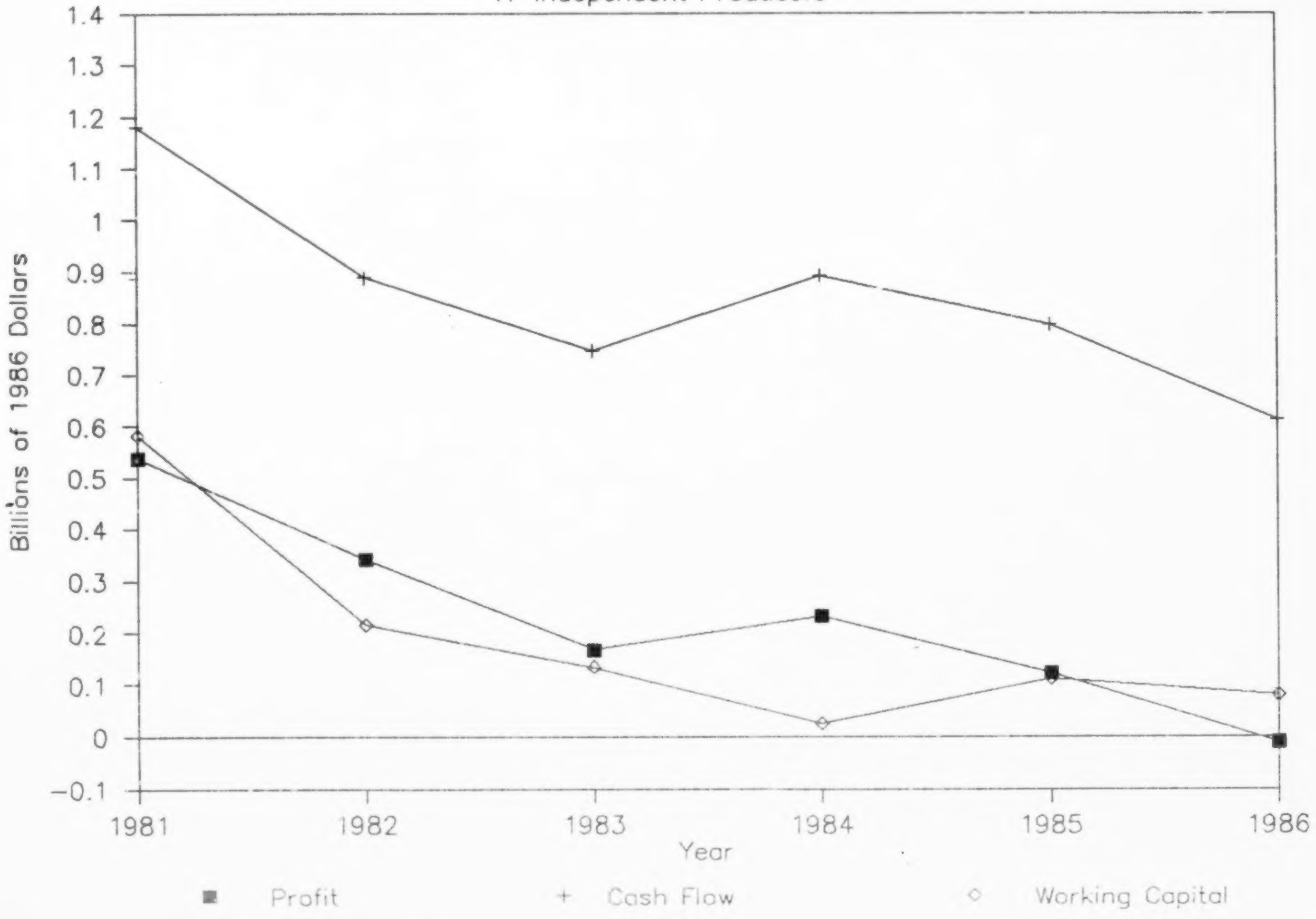


Exhibit 4.d

Financial Performance Measures

17 Independent Producers



ally the case in the industry. A successful initiative to increase exploration and reserve creation must augment the industry's cash flow and its financial resources for conducting exploration.

In considering incentives that are targeted at encouraging exploration per se, the primary focus is on the first of the two problems cited above: increasing the apparent return from exploration.

However, an important secondary effect of several of these incentives is to add to the industry's financing ability. These incentives that are primarily aimed at improving the apparent return from exploration and, in conjunction, provide additional financial resources may be most desirable because they increase the likelihood that the additional cash flow/financing capability will be channeled into exploration.

In general, there are three possible ways in which an incentive may affect expected return and thereby encourage additional exploration:

- o Increase the effective price that an exploring firm may expect to receive for producing the oil and gas that it may discover. A price support or guarantee are examples of incentives that would operate in this way.
- o Reduce the effective cost of producing the oil and gas that an exploring firm may discover. A production tax credit or reduced royalty burden are examples of incentives that would operate in this way.
- o Reduce the effective cost of exploration. An exploration tax credit is an example of an incentive that would operate in this way.

Incentives in each of these three categories may increase the expected return from exploration and thereby encourage firms to explore otherwise subeconomic prospects. However, incentives in the first and second categories benefit the exploring firm monetarily only when the firm has actually discovered and begun to produce the new reserves. Thus, there remains a considerable risk that the firm will not "benefit" from the incentive as a result of both the uncertainty of discovering resources and, as well, the prospect of ex poste changes in the incentive structure. In this light, the more effective incentive method may be by reducing the effective cost of exploration. In this way, at the same time that the expected return from exploration is increased, the exploring firm's risk is reduced in that its cash exposure for undertaking additional exploration activity is directly reduced by the incentive. The firm continues to bear the risk associated with the uncertainty of resource discovery and production prices and costs; however, exploration cost risk is reduced and there is no risk that the incentive's benefit will not be realized.

It must be recognized that incentives that reduce exploration costs may fail to stimulate exploration in frontier areas with high development and production costs, and that sizable undiscovered resources may lie in such areas. The effectiveness of exploration cost incentives will depend, in part, on market oil price expectations and on the quantity of undiscovered domestic resources that is economic at market prices.

The following discussion of incentives for increasing exploration focuses on those that affect the exploring firm's decision by reducing exploration costs. The discussion begins with an analysis of policy initiatives that could be applied to Federal leases and concludes with a discussion of initiatives that could be applied to state and private lands as well as Federal lands.

POLICY INITIATIVES THAT ARE COMPATIBLE WITH DOI'S EXISTING MANDATE TO MANAGE FEDERAL RESOURCES

A general class of incentives involves the use of "credits" to reduce exploration costs and thereby improve the expected return from exploration. Specifically, an exploring firm would be allowed to credit a fraction of its qualifying exploration/reserve creation outlays against some other liability to the government. In this way, the aggregate liability against which exploration outlays may be credited becomes the source of:

- The incentive to increase the return from exploration, and
- The additional cash flow/financing capability for increasing exploration.

The simplest way to establish a liability against which exploration outlays may be credited is to allow credits against payments to the Federal government associated with acquiring and operating oil and gas leases. This option is consistent with DOI's mandate to manage Federal resources; it defines a program that is applied only to Federal lands and draws only upon Federal lease revenue.

Exploration/reserve creation credits against federal lease payments

With this incentive, a firm would be able to credit a specified fraction of its qualifying exploration outlays on specific "frontier" Federal leases against the sum of all its lease payment obligations to the Federal government (i.e., royalties, bonuses, and rentals on all oil, gas, and coal leases held). Qualifying outlays could be defined to include secondary recovery investments. The allowed credit fraction could be defined to vary by the geographical area or nature of exploration -- that is, exploration in higher-cost, riskier exploration areas could receive a higher credit. The percentage credit could be specific to a planning area, or even specific to a lease.

The effectiveness of this, and any other credit-related incentive, in encouraging exploration depends on:

- The level of the credit -- that is, the fraction of qualifying outlays that may be credited against the firm's lease payment obligations

- The size of the firm's liability against which the fraction of qualifying outlays is being credited -- that is, whether a firm can benefit from an exploration credit will depend on whether it has lease payment obligations to which it may apply the credit.

In general, the higher the risk and uncertainty associated with a given prospect, the higher will be the credit required to cause a firm to see an advantage in exploring a prospect at current depressed prices that would otherwise have been economic at only a given higher price (e.g., $25 per barrel).

The determination of an appropriate level for an exploration credit (or a credit schedule) depends on the quantity of undiscovered, recoverable resources which is deemed in the public's interest to encourage exploring firms to see as economic.

It may be desirable to implement a credit schedule in which the credit fraction varies depending on the geographical area and character of the reserve creation activity. For example, new field wildcat activity in "frontier" OCS and onshore areas (e.g., deep water Gulf of Mexico, all of Alaskan and

Atlantic Coast offshore, and Federal onshore acreage on the Alaskan North Slope) might receive a credit of, say, 60 percent. New field wildcat activity in more mature OCS and onshore areas might receive a credit of 25 percent; and exploration activity in existing developed areas (e.g., extension drilling) and secondary recovery investments might receive a credit of 15 percent. The credit may be highest in areas in which the ratio of undiscovered resources to near-term reserve additions appears to be highest. Alternatively, the credit may be highest in areas with the greatest expected incremental reserve additions per dollar of exploration credit.

The use of a variable credit schedule would have two important benefits:

- Firms would be more strongly encouraged to explore in the higher risk, frontier areas in which significant, new discoveries are more likely. Even if few or no significant discoveries are made in such areas, the Nation's policy makers would gain improved information on the likely discovery of petroleum resources in these areas.
- By giving a stronger and presumably effective incentive for firms to explore in areas that they would now otherwise likely ignore, there is a greater likelihood that the exploration incentive will apply to new, incremental activity instead of exploration that would have been undertaken in any event.

The potential effectiveness of an exploration credit depends on the availability of a substantial liability against which the credit may be applied. That is, if firms have little or no current lease payments obligations, then the credit will be largely ineffective. At best, firms would only be able to carry the credits forward in time until sufficient obligations were incurred to allow their use.

The size of the current Federal lease payments relative to current exploration outlays provides a measure of the potential significance of funding additional exploration through credits against Federal lease payment obligations. An important consideration in comparing the exploration credit arrangement to an incentive in which Federal lease payment obligations are simply reduced (e.g., a general reduction in royalty and rental payments) is that the exploration credit arrangement is contingent upon exploration activity. That is, the exploring firm will pay less royalties, rentals, or bonuses only if it explores and makes use of the credit incentive. The extension of the lease payments reduction is contingent on the firm undertaking the exploration activity. Accordingly, the likelihood is increased that the financial benefit afforded by the payments reduction will in fact be applied to new exploration.

On balance, an exploration credit against Federal lease payments appears to be a viable mechanism for encouraging additional exploration/reserve creation activities. The credit can be set to achieve the desired incentive effect and, if desired, varied to encourage more strongly activity in certain areas. The ongoing Federal lease payments liability appears sufficiently large to fund substantial new exploration activity. One weakness of this incentive is that it would apply only to exploration occurring on Federal leases. However, the great preponderance of domestic discovery possibilities lies on Federal lands.

Incorporation of exploration crediting in lease sale procedures

Because many frontier areas remain to be leased, it is possible to establish exploration cost crediting procedures for future lease sales that are simple to administer and that provide assurance that firms will not be reimbursed for exploration costs that would have occurred without the credit. These procedures provide a Federal stimulus to exploration, yet maximize the role of the competitive marketplace in allocating exploration resources efficiently.[1]

Under this type of incentive, the government chooses offshore areas where the greatest divergence exists between the social and private value of leasing, exploration, and possible development. The characteristics of such areas are that they hold the potential for vast amounts of economically recoverable resources, but most if not all of these potential resources are not privately worth leasing now. In these areas, little or no exploration has occurred but Federal lease sales are scheduled to be held within several years.
For one or more of these selected areas, the government determines the maximum number of exploration wells it will want to be drilled, denoted by **N**. It estimates the cost of drilling these wells, say **K** dollars. It then proposes that in the sale, up to n leases will be awarded with a credit

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[1] These procedures are outlined in an internal Department of the Interior memorandum dated January 29, 1987. The following discussion is based upon this memorandum.

available of **KS** dollars per lease if an approved exploration plan is completed, where **S** is the fraction of exploration costs shared by the government. All such leases with approved drilling activity will receive a credit of precisely **KS** dollars, regardless of the actual amount of out of pocket expenditures. This method of payment avoids accounting problems and encourages exploration efficiencies, since any saving in drilling costs accrues to the lessee in full. Also, the credit should be made chargeable to any OCS lease obligation; if it is lease-specific or even area-specific, the credit is likely to be worthless to the lessee.

The bidding sessions are conducted in two parts. Initially up to **N** tracts can be awarded with the credits provided to the **N** highest winning bidders. All other bids would be rejected. Thus, no tracts are awarded in this first session without an exploration credit. Note that if there were a possibility of winning a tract and not receiving any cost-sharing benefits, bidders would discount each of their bids to reflect this possible outcome (although to the extent the sale was competitive, a large part of the credits might be reflected in the aggregate of all winning bids). By awarding leases only for tracts receiving an exploration credit, the leasing procedure reduces complications in private bid formulation and in the government's assessment of bid adequacy.

The second session of the sale would offer all tracts not among the **N** highest bids or simply not bid on at all in the first session. Thus, unsuccessful bidders in Session 1 could revise their bids in Session 2. In order to protect such bidders, their losing bids in the first session would be kept confidential at least until after Session 2 was completed.

A modification of the two-session approach would allow firms to submit dual bids: one bid contingent upon receipt of the credit, and one bid applicable in the absence of the credit. In this way all bids submitted could be announced simultaneously, as is the case under current Outer Continental Shelf lease sale procedures.

The effectiveness of the exploration credit will vary across frontier areas, depending largely upon variations in the cost of oil drilling and production. The exploration crediting scheme outlined here may not have any effect on exploration activity in the highest-cost frontier areas unless firms anticipate crude oil prices in the Persian Gulf of at least $25 per barrel (in 1987 dollars). In an analysis of exploration crediting in the Chukchi Sea planning area, for example, the credit appears to have an impact only when prices rise above $25 per barrel. A 50 percent credit is then equivalent to an oil price increase of about $2 per barrel; a 100 percent credit is worth the equivalent of a $4 to $5 per barrel oil price increase.

Royalty reductions in frontier areas

Another policy initiative to promote frontier exploration is a royalty reduction in frontier areas. Under this initiative the cash flow of the producer of frontier resources is increased (although the incremental cash flow is taxable) and the attractiveness of production from frontier areas is enhanced.

One advantage of a royalty reduction is its administrative simplicity. No new administrative mechanism would be required to implement it; no new forms would have to be submitted by producers to determine their eligibility for the incentive; and no Federal agency would need to distribute funds. The program would be entirely under Department of the Interior control.

A royalty reduction has three disadvantages. First, the initiative creates an incentive to produce rather than an incentive to explore. If a royalty reduction is applied to frontier areas, it creates an incentive to bring leases into production soon and maximize output before the royalty reduction expires. It does not encourage firms to hold extra reserves for "peaking capacity." Second, the royalty reduction is a fairly weak incentive in areas in which the expected success ratio is low. The value of the incentive to the firm must be diminished by the likelihood of a dry hole and by the lead time necessary to bring a frontier tract into production. Given the tremendous uncertainty in oil price expectations, a royalty reduction is equivalent to a crude price differential that may be in the "noise." Third, the benefits of the royalty reduction are distributed unevenly across firms in the oil industry. Holders of existing Federal leases in frontier areas would receive a "windfall," relative to holders of other leases.

Price guarantees for production in frontier areas

Like a royalty reduction in frontier areas, a price guarantee provides a direct incentive for production and only an indirect incentive for exploration. Like a royalty reduction, a price guarantee does not encourage firms to hold extra reserves for "peaking capacity." The price guarantee could involve a larger Federal outlay per barrel of frontier production than the royalty reduction; it could be more expensive to the government, and more effective in stimulating industry interest in high-cost areas such as offshore Alaska. A system of price guarantees may be regarded as a higher-cost policy option that should accompany, rather than substitute for, a system of exploration cost crediting.

POLICY INITIATIVES THAT EXTEND THE PROGRAM TO NON-FEDERAL LANDS OR REDUCE THE FEDERAL BUDGET IMPACT OF THE PROGRAM

Three aspects of the crediting schemes described above limit their effectiveness in promoting frontier exploration:

1) Credits against Federal lease revenue only provide a stimulus to exploration on Federal lands.

2) The total amount of credits against Federal lease revenue cannot exceed the annual revenue base. When oil prices are low, the funding base shrinks.

3) Credits against Federal lease revenue are useful only to Federal lessees. Even if the credits are transferable from one firm to another, they must be transferred from one lessee to another.

4) Credits against Federal lease revenue reduce Federal budget receipts and may worsen the deficit. The cost of the credit is borne by the taxpayer rather than the oil consumer.

These limitations can be overcome by expanding the scope of the proposed crediting program beyond the traditional scope of Department of the Interior activity. Three possible configurations of a credit incentive can be used to extend an incentive program to non-federal lands or reduce the federal budget impact of the program:

- Credits against Federal corporate income taxes

- Credits against a "Windfall Profits Tax" applied in conjunction with an oil import fee
- Credits for qualifying exploration outlays from an exploration trust funded by a tax on oil consumption.

Each of these policy instruments is discussed below.

Exploration/reserve creation credits against Federal corporate income taxes

This incentive works in the same manner as the credit incentive discussed above with the exception that exploring firms would be credit qualifying exploration/reserve creation expenses against their Federal corporate income tax liability instead of Federal lease payments.

The only difference between this and the lease payments credit incentive discussed above is that the exploring firm would charge a fraction of its qualifying outlays against its income tax liability. Accordingly, this discussion does not recount the general findings regarding the use of a percentage credit as an exploration incentive.

The effectiveness of this incentive both in aggregate and in its application to individual firms will depend on the amount of income tax liability available to be offset by exploration tax credits. At current depressed oil prices, a large share of the domestic oil industry has either low or negative taxable income. As a result, using the current Federal corporate income tax obligation as the liability against which exploration credits are charged may not provide an effective exploration incentive. To increase the value of the credit to firms, it may be possible to establish a system in which firms accumulate credits against future tax liabilities.

As a possible step to improve the effectiveness of a tax credit, firms might be able to receive a rebate for unused exploration tax credits. However, this possibility would involve "writing a check" to oil firms, which may not be a desirable measure. Absent such a provision, the use of an exploration tax credit when there is often little or no current tax liability at the individual firm will cause firms to seek other mechanisms for receiving the tax benefit, such as mergers/acquisitions between firms with unused tax credits and those with substantial tax liability.

As discussed previously, an exploration credit can be effective in encouraging additional exploration -- but only if there is a sufficient liability to fund the exploration credits. In this light, with many oil firms -- particularly the independent producers and other firms that rely more on upstream operations for profit generation -- having little or no current tax liability, the incentive may be ineffective.

Exploration/reserve creation credits against a floating excise tax applied in conjunction with a fixed oil import tax

This incentive would involve the following components:

- A fixed[2] tax on oil imports. The effect of the tax on consumers in raising the price of imported oil might be offset by reducing the Federal deficit and/or rebating the fee through a reduction in the general income tax.
- A tax on the profit received by domestic producers as a result of the rise in oil prices resulting from the import tax. This tax would operate similarly to the old Windfall Profits Tax.
- An option to credit a fraction of qualifying exploration outlays against the floating excise tax liability.

The exploration credit component of this incentive would operate in the same manner as the lease payments credit explained above.

In its application, this incentive will cause an apparent price increase to oil consumers. The effect of this price increase on domestic producers will be to contribute higher revenue and cash flow that could be flowed into exploration. To encourage the flow of the additional revenue into exploration, a special tax would be applied to transfer a substantial share of the incremental revenue increase to the Federal government. However, the tax would be offset by exploration credits in the same way as explained previously.

An important feature of this option is that it creates its own Federal payments liability against which exploration credits may be charged. Specifically, the size of the liability pool against which exploration credits could be charged would depend on the level of the import tax, the consequent oil price increase, and the tax rate applied to the incremental revenue received from the price increase. Accordingly, in designing this option, it would be possible to ensure that there is sufficient tax liability to fund needed exploration tax credits.

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[2] A fixed tax is preferred to a variable tax because the burden could be significantly shifted to foreign producers.

A draw-back of this incentive package is that it would discriminate against foreign oil producers and domestic importers of foreign crude and refined products. These entities would receive none of the benefit of the higher petroleum prices seen in the domestic market.

Exploration credits from a trust funded by an oil consumption tax

Exploring firms would receive fractional rebates of their qualifying exploration outlays from an exploration trust funded by an oil consumption tax. The oil consumption tax would be applied to both imports and domestic production and would raise the apparent price of all oil to consumers. Producers would not "see" a price increase, but the exploration credit would create a transfer payment from consumers to producers. Producers could receive the credit in the form of an annual or quarterly lump sum.

Under one variant of this policy option, the Federal government could establish a schedule of percentage credits for various offshore planning areas and onshore provinces according to variations in the expected benefits of exploration. The schedule of credits would be designed to try to avoid crediting exploration activity that would occur in the absence of any credit. The level of the tax would be chosen initially to be large enough to build up a surplus in the trust fund sufficient to assure firms that the schedule of percentage credits would not be revised without 12 months' notice (or perhaps even greater advance notice). The surplus would give firms an assurance that the fund would not become exhausted; it would effectively guarantee the crediting arrangement.

Under another variant of this policy option, the amount of the tax could be adjusted from year to year so that the fund would not accumulate a surplus until a certain exploration target was achieved. The target would be established annually by the Federal government and could be as simple as a total annual number of wildcat wells or as complex as a formula reflecting regional variations in exploration activity. Until the exploration target is achieved, the value of the incentive (i.e., the fraction of exploration outlays that would be rebatable from the fund) could be set according to the ratio of qualifying exploration outlays to trust fund receipts in any year. The applicable credit rate during a year would be determined by dividing the total of qualifying outlays for the year into the total tax receipts (net of administration costs) for the year.

This incentive is similar to the import fee/tax/exploration credit package discussed above. Specifically, the incentive is again provided by a credit or rebate on qualifying exploration outlays. However, the funding source of the incentive is a trust fund instead of the aggregate of individual firm payment liabilities to the government. Other important differences from the import fee package include:

- The entire burden of the tax would fall on domestic consumers (i.e., there is no ability to shift the incidence to foreign producers).
- The consumption tax would not discriminate by source of supply (e.g., domestic production or imports). All oil consumption would be charged with the indicated tax. The tax could be applied at the point of import entry, or for domestic production, at the refinery acquisition point.
- The potential for a firm to use the exploration incentive would not be limited by the amount of its own Federal payments liability. Rather, in any year, the limit on the use of the incentive would be determined by the the trust fund's aggregate tax receipts and the aggregate amount of qualifying exploration outlays. The consumption tax could be set to provide a relatively predictable level of fund receipts, which would in turn be available to support additional exploration activity. The incentive package would operate as an "off-budget," self-financing vehicle. The fund could not run a deficit as the credit rate in any year would be determined on the basis of the receipts and qualifying outlays for that year.
- Because the incentive does not operate through applying a credit against a Federal payment liability (e.g., lease or tax payments), the Federal government would have to pay the exploring firm the credit value it is due from qualifying exploration outlays.

Like the credit arrangements discussed above, the effectiveness of this incentive would depend on the level of exploration credit provided. In this case, the aggregate level of credit able to be extended would be determined by the consumption tax rate and the associated accruals to the trust fund. As already discussed, the actual credit rate would then vary with the applications for rebates from the fund.

As for the other credit arrangements, the credit rate could be set up as a schedule varying by the location and character of exploration outlays.

This incentive package provides a viable approach to encouraging additional exploration. Like the import fee/tax/exploration credit package, the incentive would be administratively complex. However, this package would overcome many of the objections that have been raised against import fees, and would be consistent with policy proposals to raise Federal taxes on petroleum products such as gasoline.

CONCLUSIONS

Promotion of exploration in frontier areas would improve the nation's ability to increase oil production in response to oil price increases. In the recognition that future oil price increases might lead to a relatively rapid conversion of indicated and inferred reserves to proven reserves, efforts to provide longer term benefits from the stimulation of new exploration/reserve creation probably should aim at so-called undiscovered economically recoverable resources--those resources that are contained in undeveloped and frequently unexplored areas. Moreover, because the greater probability of finding significant, new petroleum reserves may lie in higher-risk, frontier areas, emphasis might be given to such areas in efforts to stimulate exploration activity. Exploration in such areas will also contribute valuable information on resource potential that is vital to the formulation of coherent longer-term national energy policy.

To be cost-effective a Federal policy to promote oil exploration must tie receipt of economic incentives to completion of exploration or reserve creation activity. Incentives aimed at cash flow enhancement alone are not likely to be a cost-effective method of promoting exploration. At today's oil prices, major oil firms may use only a fraction (perhaps one-sixth) of their cash flow from operations to support exploration activity.

In general, the measures that were found to be most effective in promoting additional exploration/reserve creation activity are those that reduce the effective cost of exploration. Compared to measures that would reduce development/production costs or increase production prices, measures that reduce exploration cost do not expose the exploring firm to the risk of resource discovery in order to benefit from the measure. In addition, the cash-flow benefits of measures to reduce exploration cost are immediate, thus directly improving the ability of firms to finance and undertake additional exploration activity. Measures that are recommended for further consideration include:

- Exploration cost credits against Federal lease payments (i.e., royalties, rentals and bonuses on offshore and onshore Federal oil and gas leases)
- Exploration cost credits from an "Exploration Trust" funded by a petroleum product consumption/excise tax (e.g., a gasoline tax)
- Exploration cost credits against a floating excise tax applied in conjunction with a fixed oil import fee.

All of these measures are aimed at promoting reserve and "near reserve" creation by reducing the effective cost of exploration to the exploring firm. In addition, the measures provide financial support for expanded exploration activity. However, by tying receipt of the financial support to the undertaking of exploration activity, these measures should be more effective than simple "cash-support" measures (e.g., a reduction in Federal royalty payments) in promoting additional exploration.

CHAPTER 5

POLICY INITIATIVES DESIGNED TO DAMPEN CYCLICAL FLUCTUATIONS IN DOMESTIC EXPLORATION ACTIVITY

Although in the early 1980s many analysts expected oil prices to increase steadily, it now appears that the world oil market will go through boom and bust cycles for many years. Large fluctuations in oil prices are likely to occur even in the absence of supply disruptions. Rather than fitting a predictable cyclical pattern, oil prices are likely to be unstable and difficult to predict. The change that has occurred in oil price expectations has important implications for national energy policy.

To mitigate the adverse impacts of oil price instability on the U.S. economy, the Federal government may choose to dampen cyclical fluctuations in domestic exploration activity. There are three reasons why it may be in the public interest to have the Federal government assume such a responsibility:

- **Supporting oil exploration during the trough of an oil price cycle will reduce our nation's dependence on oil imports.** Support for oil exploration during periods of low oil prices will probably raise annual reserve additions and will preserve the oil industry's capacity to increase domestic supply in response to high oil prices. The incremental reserve additions can be converted to production during high-price periods, when domestic resources are most needed. Maintenance of the industry's exploration and development capability will improve the industry's ability to raise production if the "peak" of the cycle last several years.

- **Dampening the "boom and bust" cycle of domestic oil exploration would reduce the adjustment costs associated with moving labor and equipment in and out of the oil industry in response to oil price swings.** The benefits of stabilizing the level of exploration activity would be reduced unemployment, increased labor productivity, and increased security of financial institutions.

- **Cyclical fluctuations in oil exploration activity may be exacerbated by tightness in capital markets.** Investors' aversion to risk may cause investment decisions to be made on such a short-term basis that economically efficient investment opportunities are bypassed. In addition, investors' price expectations may be unduly influenced by recent events. During an oil boom, investors in the oil industry may be unreasonably optimistic about oil prices; during a bust, investors may be unreasonably pessimistic.

The purpose of these initiatives is to mitigate the adverse economic effects (and adverse Federal budget consequences) of cyclical fluctuations in oil prices. During the peak period, U.S. import dependence is reduced by production from the incremental reserves that were added during the trough as a result of Federal support, and drilling cost increases are moderated because skilled manpower is retained by the drilling industry during the trough period as a result of Federal support. During the trough period, the program reduces Federal outlays related to oil industry unemployment and oil-related bank failures, and generates increased Federal lease revenue and income tax receipts.

POLICY INSTRUMENTS THAT COULD BE USED TO DAMPEN BOOM AND BUST CYCLES

To reduce our nation's dependence on oil imports, the Federal government could provide support for exploration activity during the trough of an oil price cycle. If a policy of dampening boom and bust cycles is endorsed, incentives for exploration must be provided during periods of low oil prices. The question may be raised, however, whether the government should also take steps to diminish exploration activity during the peak of the cycle. In this context it is important to distinguish exploration incentives from production incentives. Clearly the government should encourage domestic production during a period of high oil prices; measures such as oil price controls or the Windfall Profits Tax may only exacerbate the non-OPEC oil supply situation that led to price increases.

If the period of high oil prices is only temporary, the nation may find new reserves during the peak of the cycle, only to produce them during the trough. The domestic oil industry's need to recover the costs of exploration investments made during boom times may force the industry to produce oil during a period of low oil prices. Given the uncertainty of oil prices and the industry's need for cash flow in lean times, firms may choose to produce reserves soon after they are discovered rather than hold them as a hedge against possible price increases. Incremental investments in exploration made during a boom may not, in retrospect, be economic, due to the high marginal cost of exploration activity during a boom.[1]

Given the low reserve/production ratio of the United States relative to major oil-exporting nations, however, it is perhaps better to accept the risk that the domestic industry will conduct "too much" exploration than to implement policies that could cause industry to conduct too little. For this reason it does not appear worthwhile to evaluate policy options that would shave the "peak" of an exploration boom. The only options worth considering are those that raise the level of exploration activity between peaks.

The policy instruments that could be used to raise exploration activity between oil price peaks are very similar to the instruments, discussed in Chapter 4, that could be used to promote exploration in frontier areas. First, there is a set of initiatives that could be funded by Federal lease revenue:

- Adjustable exploration/reserve creation credits against Federal lease payments. The percentage credit may vary over time, or the definition of qualifying wells may vary over time.

- Adjustments in the royalty rate on frontier areas. The rate may be higher in "peak" periods than in "trough" periods.

- Price guarantees for production from Federal leases in frontier areas. No adjustment to the terms of price guarantees is needed; they will naturally dampen cyclical fluctuations in exploration activity.

All of these initiatives may be regarded as extensions of the Department of the Interior's responsibility to manage oil and gas resources on Federal lands.

Second, there is a set of initiatives that could be funded by excise taxes that vary over time:

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[1] If oil prices were to increase and then remain at a high level indefinitely, a high level of domestic exploration activity would be beneficial to the nation. On the basis of the discussion in Chapter 1 this scenario appears to be unlikely, however.

- Exploration/reserve creation credits against a floating excise tax applied in conjunction with a fixed oil import fee.

- Exploration/reserve creation credits from a trust funded by an oil consumption tax. The excise tax rate could vary over time, falling to zero during periods of high prices.

Although these initiatives would expand the scope of the program well beyond the traditional responsibilities of the Department of the Interior, they would help to:

- Stabilize the level of oil exploration activity on state and private lands

- Increase the dollar amount of the funding base used to support exploration during a period of low oil prices

- Ease or remove the impact of the program on the Federal deficit.

In short, the development of a policy to dampen the boom and bust cycle of domestic oil exploration should not require any additional administrative mechanism, given a policy of promoting exploration in frontier areas. Most of the difficult questions regarding administrative feasibility, geographic scope, and prevention of "cheating" must be faced in the design of a program to stimulate frontier exploration, not a program to support exploration when prices are low.

TIMING OF RECEIPTS AND EXPENDITURES

One of the issues that must be resolved in the design of a program to support exploration in a period of low oil prices is the question of timing of funding receipts. The timing of receipts will probably depend upon the choice of funding source. Funding obtained from Federal lease revenue will reach a peak when oil prices peak; if this mechanism is used to accumulate a fund, it is best for the fund to accumulate a surplus during boom times. Funding from any tax on consumption, however, is easiest to obtain in the "trough" period when oil prices are low. Arguably, excise taxes on petroleum products are needed during a period of low oil prices to give consumers an economic incentive to conserve energy. Perhaps the best funding formula would be a combination of excise taxes during periods of low oil prices, and a set-aside of Federal lease revenue during periods of high oil prices.

Because it is impossible to predict the future path of oil prices, or the remaining, domestic resource base, it is impossible to know with certainty the level of exploration incentive needed to achieve stability. Judgment by Federal policymakers will be required to establish the tax or crediting parameters that determine funding levels. Because oil prices are uncertain it is probably not possible to develop a formula that will automatically establish the levels of tax or crediting parameters.

The record of the past decade shows that it is difficult to achieve the political consensus necessary to support programs that reduce dependence on oil imports at a time when oil prices are low. Until 1986 the Strategic Petroleum Reserve, for example, was filled largely at post-1978 prices around $30 per barrel, not at pre-1973 prices of $2 per barrel.

To manage oil and gas resources in an era of oil price instability, the Department of the Interior will need to establish policies toward oil and gas exploration that will strengthen the U.S. economy and reduce dependence on oil imports over the long term. A program designed to dampen boom and bust cycles in oil exploration could become an element of this long-term policy.

APPENDIX A

HOW OIL PRICE SHOCKS CAN OCCUR WITHOUT SUPPLY DISRUPTIONS

From the U.S. perspective, an oil price shock may be defined as a spot crude oil price (or spot crude oil value) increase or price decrease (denominated in U.S. dollars) that satisfies the following criteria:

- the weekly percentage change in price is high, relative to normal weekly spot price movements
- the price change is perceived to last for several months or years, and therefore affects capital investment decisions
- the magnitude of the price change is large enough to impose significant adjustment costs on the U.S. economy. The two great price shocks of the 1970s occurred after the beginning of the Arab embargo of mid-October 1973 and after the beginning of the Iranian revolution in late October 1978.[1] The term "spot crude oil value" is used to describe time periods in which spot crude oil markets were sufficiently thin that spot product prices provided a better measure of the market value of crude oil.[2] Essentially the definition of "price shock" presented here states that a price change is a price shock if it imposes significant adjustment costs.

The economic effects of oil price shocks may be associated with price increases or price decreases. The cost-effectiveness of policy alternatives designed to mitigate price shocks will depend upon the expected likelihood and expected severity of such shocks. Among the factors that can cause price shocks are supply disruptions; both the Iranian revolution and the OAPEC embargo on oil shipments to countries supporting Israel were supply disruptions. In this appendix, factors other than supply disruptions are examined.

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[1] The price pattern in the weeks following each of these crises is illustrated in a graph published in Philip K. Verleger, Oil Markets in Turmoil (Cambridge, Mass.: Ballinger, 1982), p. 32.

[2] Given an estimate of refinery margins and the percentage mix of refined products associated with a particular crude oil, it is possible to calculate the value of crude oil on a netback basis. The concept of spot crude oil value is explained in Verleger, Oil Markets in Turmoil, pp. 15-20 and 263-273.

To demonstrate the possibility of oil price shocks without supply disruptions it is necessary only to look at oil price trends from January 1986 to the present. The crash in oil prices occurred without a major change in oil production or transportation capacity. No embargo or blockade was lifted; no major facilities were suddenly returned to service after being damaged by war, revolution, or natural catastrophe. In the absence of fundamental changes in the supply/demand picture, the price of oil fell dramatically to around $10 per barrel and rebounded to around $18 per barrel.

If there were convincing evidence that oil prices will now stabilize at $18 per barrel, or any level below $25, however, the oil price changes of 1986 might be regarded as beneficial. While the U.S. economy may have suffered from the volatility of oil prices, the economic benefits associated with a lower oil price level would likely outweigh the adjustment costs associated with the price changes of 1986. Unfortunately, there is no such convincing evidence. On the contrary, the evidence is that oil prices will continue to be highly volatile.

This appendix explains the ways in which oil price shocks can occur without supply disruptions. The appendix begins with a discussion of factors that make crude oil prices change over time. Next, factors affecting recent oil price changes are identified. The current market situation is summarized in a Base Case scenario in which no price shocks are projected. Two departures from the Base Case are examined: a Rapid Price Increase scenario and a Rapid Price Decrease scenario. Finally, the possibility that oil prices may become cyclical - that rapid price increases may alternate with rapid price decreases - is considered.

FACTORS THAT MAKE CRUDE OIL PRICES CHANGE OVER TIME

Although oil prices fell sharply in 1986, the members of OPEC continue to exert a powerful influence on oil prices. This point is demonstrated by studies of the global supply curve for oil, which suggest a long-run marginal cost well under

$10 per barrel.[3] If OPEC were to permanently collapse and if all nations acted competitively the price of oil would fall below $10 per barrel and remain there for at least a decade. The price floor that will be reached by a temporary collapse of OPEC is currently around $7 per barrel. The short-run ceiling on oil prices is determined primarily by OPEC's ability to enforce strict production cutbacks, while the long-run ceiling is determined by OPEC's production cutbacks plus the elasticities of world demand and of non-OPEC supply.

The difficulty of predicting oil prices is attributable largely to the fact that OPEC is neither a monopolist -- an organization with the power to keep prices at rent-maximizing levels indefinitely -- nor a powerless organization. At one time or another prices may be determined by competition, oligopoly, or monopoly behavior, or simply by irrational political decisions. OPEC's output fluctuations do not fit a consistent, predictable model (e.g., the behavior of a competitive firm according to microeconomic theory).

Prices rise or fall as the global supply curve is "shifted" to the right or to the left by OPEC. The short-term effect of these shifts in the supply curve is an increase or decrease in global oil inventories.

Short-term oil prices are highly sensitive to output fluctuations that represent only a few percentage points of world oil supply, i.e., fluctuations equivalent to one or two weeks' worth of inventory. The cost of inventory is sufficiently large, and the long-term price trend is sufficiently uncertain, that the oil market responds to inventory changes that might seem small relative to inventory changes in some other commodity markets. In the oil market an "overhang" of 6 days' production (about 300 mbd) is considered large. The overhang in sugar stocks in August 1985 (the excess above the "normal" stock level) was equivalent to 87 days' production. Global stocks of maize are expected to increase from 41 days' to 84 days' production, in the 12 months ended September 30, 1986. The portion of world coffee stocks held by producers in September 1985 was equivalent to 218 days' world production.[4]

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[3] See, for example, M.A. Adelman, "An Unstable World Oil Market," The Energy Journal 6,1 (January 1985), pp. 17-22.

[4] See International Monetary Fund, Primary Commodities: Market Developments and Outlook (May 1986), pp. 22,38.

For a given quarter it is reasonable to consider both global oil demand (excluding inventory accumulation) and non-OPEC supply to be highly inelastic, yielding a highly inelastic demand curve for OPEC oil. Prices rise or fall in a given quarter depending on what OPEC produces relative to the demand for its oil in that quarter. OPEC may overproduce or underproduce, relative to the production level that would achieve a constant oil price level.

In the short run there are three determinants of the demand for OPEC oil:

- world oil demand
- non-OPEC production, and
- inventory behavior.

The first two factors are typically viewed as long-term issues, because they are less volatile in the short run. Inventory behavior is more volatile, and it is the primary determinant of prices in the short term. Inventory behavior is driven by buyers' and sellers' perceptions concerning the direction of OPEC production, world oil demand, and non-OPEC production.

There are three determinants of the difference between the quantity of OPEC production and the demand for OPEC oil:

- OPEC's ability to enforce production quotas or price levels
- OPEC's ability to predict the production quota that will yield a specific price level in spot markets
- Disruptions in the global supply of oil caused by wars, revolutions, accidents, natural disasters.

In 1987 an important factor may be OPEC's ability to enforce production quotas or price levels. The strength or weakness of the cartel depends upon the member nations' willingness to "cheat" against a cartel agreement (by offering under-the-table discounts or by producing above a quota). An equally important sector is Saudi Arabia's willingness to act as a swing producer, regardless of the enforcement of OPEC agreements. The 1986 price shock would have occurred far sooner if they were unwilling to compensate for other's cheating.

A higher growth rate in demand for OPEC oil suggests a higher long-term oil price level. The accuracy of past oil price forecasts demonstrates, however, that it is very difficult to predict long-term oil price trends.

OIL PRICES AND OPEC CAPACITY UTILIZATION

One of the methodologies used by the Energy Information Agency (EIA) to project oil prices is based on projections of OPEC capacity utilization (production divided by production capacity). The model projects oil price changes (in real dollar terms) based on OPEC capacity utilization. When OPEC's capacity utilization is over roughly 80 percent, prices rise; under 80 percent, prices fall. This explanation of price changes may be termed the capacity utilization hypothesis.

This approach is intuitively appealing. As a rule of thumb, the larger OPEC's share of the world oil market the greater the possibility that it could successfully increase prices. But the lower the capacity utilization, the more likely that cash-strapped OPEC members might cheat on quotas, thus lowering prices.

Unfortunately, however, the capacity utilization hypothesis has proven itself unreliable as a forecasting tool. The capacity utilization hypothesis predicts that the more OPEC produces in a given year, the more prices will increase (as capacity utilization increases). This is simply not true, as was shown during 1986 when unrestrained OPEC production sent prices tumbling. And as early 1987 is showing, lower OPEC production and lower OPEC capacity utilization is leading to higher prices. The capacity utilization hypothesis would predict exactly the opposite.

The theoretical relationship developed by the EIA is implausible unless one applies a certain set of assumptions and conditions. The capacity utilization hypothesis implicitly assumes that OPEC acts as a production-taker. If world oil demand is 45 mbd and non-OPEC production is 25 mbd, the model assumes that OPEC will produce 20 mbd. The higher the demand for OPEC oil, the higher oil prices go (assuming constant OPEC production capacity).

Unfortunately, OPEC does not always act as a production-taker. It does not always produce to meet the difference between world oil demand and non-OPEC production. It did not do so in 1986 and is not doing so thus far in 1987. The use of the capacity utilization hypothesis in the short-run is prone to error since in the short run OPEC may produce substantially above or below the demand for its oil. The difference is made up by additions to or withdrawals from commercial inventories.

Because the capacity utilization hypothesis does not predict short-run price changes accurately it cannot predict long-run prices, despite the long term stability of inventories. The capacity utilization hypothesis does not predict prices but the percentage price change from year to year. Such a model must be accurate in the short-term to be accurate in the long term.

Prices rise or fall depending on what OPEC produces relative to the actual demand for its oil. Using the previous example, if the demand for OPEC oil is 20 mbd and if OPEC produces 20 mbd then the EIA's empirical relationship will hold. But if OPEC produces over the demand for its oil (as it did in 1986) or under the demand for its oil (as it is doing in 1987) then prices may fall or rise in patterns totally unrelated to what the capacity utilization hypothesis predicts.

FACTORS AFFECTING RECENT OIL PRICE CHANGES

The world oil supply/demand balance for the years 1979, 1981, 1984, 1985, and 1986 are shown in Exhibit A.1. A quick review of these figures indicates many of the recent trends which have influenced the market during the 1980s:

- Oil demand is down
- Non-OPEC production is up sharply, and
- OPEC production is down sharply.

These trends were the strongest between 1979 and 1985. In 1985/1986, these trends began to reverse.

These factors are, naturally, inter-related. The sharp rise in prices in the late-1970s and early-1980s led to a variety of energy and, more specifically, oil conservation efforts aimed at reducing energy-related costs and oil imports. Some of these efforts included legislation such as the Fuel Use Act (which prohibited the construction of oil-fired power plants), industrial fuel switching (e.g., from oil to coal), and smaller and more fuel-efficient automobiles. High oil

Exhibit A.1

World Oil Supply and Demand: 1979 through 1986

	1979	1981	1983	1985	1986
DEMAND (millions of barrels per day)					
U.S. consumption	18.2	15.6	14.6	14.9	15.5
Other Free World consumption	34.2	32.1	30.6	30.7	31.1
Government stockpiling	0.1	0.4	0.2	0.1	0.1
Inventory buildup (1)	1.2	0.0	0.0	0.0	0.9
Total Free World demand	53.7	48.1	45.4	45.7	47.6
SUPPLY (millions of barrels per day)					
U.S. production	10.2	10.2	10.3	10.6	10.2
Other non-OPEC production (2)	10.8	12.2	14.2	16.0	16.4
Inventory drawdown	0.0	1.1	0.8	0.3	0.0
Net communist exports	1.1	1.1	1.6	1.6	1.8
OPEC production	31.6	23.5	18.5	17.2	19.2
Total Free World supply	53.7	48.1	45.4	45.7	47.6
Net U.S. oil imports	8.0	5.4	4.3	4.3	5.3
Crude Oil Prices (3) (US dollars per barrel)					
Arab Light	13-18	32-39	28-30	27-28	10-27

(1) Includes floating stocks and oil in transit
(2) Free World only. Includes production of crude oil and natural gas liquids, other hydrogen and hydrocarbons for refining feedstock, and refinery processing gains.
(3) Official prices for 1979, spot prices thereafter

Source: Hagler, Bailly & Company based on information supplied by the IEA, the EIA, the API, and the trade press.

prices promoted alternative energy sources and conservation programs. Synfuels, solar, shale oil, and gasohol alternatives emerged, while home insulation tax credits, EPA-mandated mileage standards, and a 55 mph speed limit cut into demand. The sharp rise in energy prices also inhibited economic growth, further curtailing oil demand.

Higher non-OPEC oil production is a direct consequence of higher oil prices and the desire for enhanced national energy security. As energy prices rose, so too did the economic incentive to find and develop new fields. The Alaskan North Slope and North Sea fields are examples of areas which may not have been developed had it not been for higher oil prices. Oil exploration and development incentives to promote energy security, usually in the form of favorable tax treatment relative to the investment and/or the resulting profits, also contributed to increased non-OPEC production. OPEC production did not fall because of any physical or economic reasons. When acting as a price-setting cartel, OPEC has operated as a production-taker; that is, OPEC produces oil at a rate sufficient to meet the difference between world oil demand and non-OPEC production. By so controlling the supply/demand balance, OPEC aims to control prices. As demand fell and non-OPEC production grew, the demand for OPEC oil and, hence, OPEC production fell also.

As prices moved inexorably downward during the early 1980s, OPEC lowered production and prices in an attempt to stabilize a deteriorating supply/demand balance. OPEC members that had planned for year after year of climbing oil demand, prices, and export revenues were shocked. For Saudi Arabia, oil revenues declined by roughly 80 percent between 1980 and 1985. And as prices and export revenues fell, OPEC members saw their debts rise and their current account balances decline.

OPEC's attempts to stabilize prices by setting lower and lower production quotas failed as some OPEC members, heavily burdened by debt and in need of dollars, produced in excess of their quotas. Large, price-induced commercial inventory drawdowns also contributed to the worsening supply/demand imbalance (generally, commercial inventories rise with rising prices and fall with falling prices). In order to move these extra supplies into the marketplace as surreptitiously as possible, a variety of hidden price discounting mechanisms were established to undercut official prices. Saudi Arabia undertook the role of the cartel's "swing producer," lowering production to keep total OPEC production under quota, thus helping to prop prices.

But by late 1985, Saudi Arabia had grown tired of the consistent cheating by fellow OPEC members. Official prices had fallen to $27 per barrel, with much crude available on the spot market for $2 to $4 under that. Saudi production had fallen to nearly 3 mbd from highs of roughly 10 mbd. Saudi Arabia abandoned its role as the swing producer in OPEC, initiating a netback pricing policy that led to a sharp rise in OPEC oil output and a consequent plunge in oil prices.

The new Saudi policy appeared to be a major setback for OPEC. For years the cartel had failed to operate as one -- it succeeded in setting neither production nor prices. Price-setting mechanisms moved from OPEC to the growing spot and futures markets. There was increased talk concerning the "commoditization" of crude oil, that crude oil was no different than pork bellies or orange juice. The future looked bleak for OPEC until such a time that the supply/-demand balance turned around. Former Saudi oil Minister Yamani even suggested that OPEC disband for a few years.

In the summer of 1986 prices fell below $10 per barrel. The low prices in 1986 fostered growth in demand and a decline in non-OPEC production.

Several of the energy supply options that were considered promising in 1979 have become less attractive. Synfuels, solar, and shale oil have become uneconomic, gasohol endangered, and nuclear discredited by Three Mile Island and Chernobyl.

Demand is on the rise as well. Between March 1979 and July 1986, gasoline demand did not exceed 7.6 mbd for any one week reported by the American Petroleum Institute (API). Since July 5, 1986, there have been five separate weeks where demand was higher than at any point in the 1979-1986 period preceding. In two of the weeks, demand penetrated the 8 mbd mark for the first time since 1978. Gasoline demand has returned to pre-conservation levels.

At the same time, oil and gas exploration budgets have been severely reduced, and the oil that the United States will need in the mid- to late-1990s has not yet been discovered. According to a recent API survey, capital and exploration expenditures on worldwide petroleum operations by the 15 leading petroleum companies declined nearly 40 percent during the first nine months of 1986 from the same 1985 period. This has contributed to the recent decline in U.S. crude oil production from over 9 mbd to roughly 8.2 mbd. In view of recent exploration trends, many market observers are predicting that U.S. crude oil production will fall further.

The trend of higher demand and falling production -- both in the United States as well as other industrialized countries -- has led to two major, inter-related concerns:

1. Higher world oil demand and lower non-OPEC production will result in increased demand for OPEC oil, leading to the possibility of significantly higher oil prices

2. The same demand/production shift will lead to increased imports, detrimentally affecting U.S. energy security and, especially at higher prices, the U.S. economy.

Today the line between an ineffective OPEC (and $10 per barrel oil) and an effective OPEC (and $18 per barrel oil or more) is very thin. By late 1986 OPEC had apparently sufficiently learned the pains of an uncontrolled oil market. It eliminated netback pricing and established new, low production quotas as well as a new fixed priced scheme. The market responded quickly, and prices shot up from $10 to roughly $18 per barrel virtually overnight. Whether prices stay at that level throughout 1987, or whether they increase further or fall back to 1986 levels, will depend on a number of factors.

The potential for oil price shocks in the next twelve months is illustrated by three plausible price scenarios:

1. The Base Case scenario: OPEC reverts to "reasonable" and "expected" cheating on quotas in the spring but for the most part succeeds in establishing fixed prices around $18 per barrel

2. The Rapid Price Increase scenario: Prices surge to near $30 per barrel

3. The Rapid Price Decrease scenario: Prices plunge to near $10 per barrel.

None of these scenarios contains a supply "disruption."

DESCRIPTION OF THE BASE CASE SCENARIO

Global crude oil demand

In the Base Case scenario (see Exhibit A.2), the annual average rate of growth is in the range of 1.0-1.5 percent. Demand in each quarter of 1987 is projected to exceed demand in the corresponding quarter of 1986.

This generally bullish assessment of 1987 demand trends is plausible for a number of reasons, primarily the decline of the dollar. Over the past year, most currencies -- including the Japanese yen, the German mark, and the Italian lire--have risen roughly 20 to 25 percent against the dollar. Oil prices during the first half of 1987 will be below 1986 levels in both dollar and local currency terms, while oil price increases in the second half of 1987 (relative to depressed second half 1986 levels) will be dampened by the weak dollar.

Some of the transitory demand gains made by oil during 1986 owing to switching away from natural gas will probably be lost during 1987 as natural gas prices become relatively more competitive in the United States and Europe. The loss in heavy fuel oil demand as crude prices in the United States exceed roughly $15/bbl will be on the order of 400,000 bd. But the overall trend will be for slow, steady economic growth fueled by the lower oil prices with oil consumption growing at roughly half of the rate of growth of the world's economy.

Non-OPEC crude oil production

Revised figures published recently by the U.S. Department of Energy show 1986 U.S. oil production was much lower than earlier estimates, and in-line with earlier predictions made by the American Petroleum Institute (API). The new figures indicate the effect of lower prices on production. Overall, DOE estimates 1986 crude oil production was down 3.4 percent to 8.7 mbd from year-earlier levels. But in the fourth quarter of 1986 the drop was more pronounced: 6.7 percent under fourth quarter 1985. The question for 1987 is whether or not this trend will continue.

In the Base Case scenario 1987 U.S. production will be down only slightly relative to year-earlier levels. This projection is based on the assumption that much of the production losses during 1986 were "one-time" shutdowns of stripper wells.[5] Much of the 1986 loss in non-OPEC production has already been made up by large gains in production made recently by developing countries, whose overall output increased roughly 300,000 bd in the fourth quarter of 1986 from the third quarter 1986 levels.

At the same time U.S. production is falling, a number of non-OPEC members have pledged to support OPEC in the form of lower oil production and/or exports. Much of this support is non-substantive, though the market likes to hear these kinds of words. Both Norway and Egypt have promised production cuts -- not against 1986 levels but rather planned 1987 levels. 1987 production for both countries will be virtually unchanged from 1986. And the Soviet Union's promise of lower exports would appear not to be terribly significant as exports are seasonal and not particularly large, and poor weather during January may have forced reduced exports anyway.

Inventories

Inventories will be drawn down in 1987; there is no way to avoid the simple mathematics of the situation. OPEC production in the Base Case scenario is predicted to average roughly 1.0 to 1.5 mbd lower in 1987 than in 1986, non-OPEC production will be down perhaps 0.3 to 0.5 mbd, and consumption will be up on the order of 0.3 to 0.7 mbd. This adds up to an unavoidable stock draw as long as OPEC maintains production discipline.

The real question is whether or not the rate of inventory drawdown will be sufficient to keep spot prices levels near OPEC's new official prices, or whether it is likely that prices will fall in the Spring or later in the year. There is no "correct" level of inventories at which market players will feel comfortable. Inventories are increased or decreased in response to the anticipation of the future direction of oil prices. Inventories are dumped when the market feels prices are falling or will fall, just as inventories are increased when the market is convinced that there is significant upside price potential. In the end, inventory behavior and prices ultimately depend on the most elusive of all factors: market psychology.

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[5] This projection is optimistic relative to the API outlook. API sees continued, significant U.S. production cuts.

In the Base Case scenario stocks are drawn during the first quarter of 1987 at the large but not overwhelming rate of 2.5 mbd (see Exhibit A.2). The market can easily absorb a drawdown of this magnitude. A mild second quarter drawdown of 0.4 mbd is also expected. These figures are based on estimates that OPEC will produce between 17.6 and 17.7 mbd of oil during the first half of the year.

These figures indicate that the market will be drawing stocks at a rate 1 mbd faster than it normally would during the same time period. This would remove roughly 180 million barrels of oil from the market during the first half of the year, still less than the oil "overhang" in the market which many analysts have estimated to be around 300 million barrels. In view of recent revisions in estimates of U.S. oil production revisions, 200 million barrels would appear to be a more accurate estimate. Consequently, the Base Case scenario envisions stock draws through mid-1987 which will completely eliminate the "overhang" placed in the market due to excess OPEC production during 1986. This rate of stock draws is sufficient for OPEC's new fixed price system to succeed, although OPEC's plans for second half 1987 production increases will have to be tempered somewhat.

OPEC production

A major uncertainty in the production equation is Iraq. Iraq's output is at present technically constrained to around 1.7 to 1.8 mbd. The completion of the final tie-in on the Petroline loop to Yanbu will boost Iraqi production capacity to 2 mbd. By the end of the second quarter of 1987, expansion plans on the pipeline through Turkey will also be completed, boosting overall Iraqi production capacity to nearly 2.5 mbd.

With the war currently not faring too well for Iraq, there is a strong possibility that Iraq will increase production and ignore the current OPEC accord just as oil demand is falling in the Spring. And it is unlikely that Saudi Arabia will use its ownership of the Petroline outlet to Yanbu to visibly pressure Iraq to lower production, though some behind-the-scenes pressure is possible. At the same time, neither Saudi Arabia nor Kuwait seem likely to renew their "war relief" crude agreement with Iraq, which accounts for roughly 300,000 bd. The net result if Iraq produced to capacity would be an increase of approximately 400,000 bd.

Exhibit A.2

Projected Free World Oil Demand, Supply, and Inventories
Scenario 1: The Base Case Scenario

	First Quarter 1987	Second Quarter 1987	Third Quarter 1987	Fourth Quarter 1987	First Quarter 1988
DEMAND (millions of barrels per day)					
U.S. consumption	16.0	15.4	15.6	15.9	16.2
Other Free World consumption	32.1	30.8	31.3	32.1	32.6
Government stockpiling	0.1	0.1	0.1	0.1	0.1
Inventory buildup (1)	0.0	0.0	0.0	0.0	0.0
Total Free World demand	48.2	46.3	47.0	48.1	48.9
SUPPLY (millions of barrels per day)					
U.S. production	9.8	9.7	9.7	9.6	9.7
Other non-OPEC production (2)	17.2	17.2	17.2	17.3	17.4
Inventory drawdown	2.3	0.0	0.0	0.6	1.5
Net communist exports	1.2	1.8	2.0	1.6	1.3
OPEC production	17.7	17.6	18.1	19.0	19.0
Total Free World supply	48.2	46.3	47.0	48.1	48.9
Net U.S. oil imports	5.5	5.7	5.9	6.1	6.0
Crude Oil Prices (3) (US dollars per barrel)					
U.S. West Texas Intermediate	17-19	16-18	17-19	18-21	19-22
U.K. Brent Blend	17-19	15-17	16-18	17-20	18-21
Arab Light	16-18	14-16	14-17	16-18	17-19

(1) Includes floating stocks and oil in transit
(2) Free World only. Includes production of crude oil and natural gas liquids, other hydrogen and hydrocarbons for refining feedstock, and refinery processing gains.
(3) Quarterly average of spot prices

Source: Hagler, Bailly & Company based on information supplied by the IEA, the EIA, the API, and the trade press.

Iran is the other major uncertainty. As is widely expected, Iraq will likely succeed in limiting its production well below its new 2.25 mbd quota. Iran will probably only be able to produce on the order of 1.5 to 1.9 mbd throughout the year, giving roughly 350,000 to 750,000 bd of output for other OPEC members to absorb without sending OPEC over its total output quota.[6]

Overall, in the Base Case scenario OPEC crude production exceeds the 15.8 mbd quota by roughly 400,000 bd. To a large extent, production by Iraq in excess of their quota will be offset by below-quota Iranian production. Total OPEC production should still exceed the quota, however, owing to minor cheating by a variety of members, particularly the U.A.E.

In the Base Case scenario OPEC generally adheres to its new production quotas, but Iraq and some of the traditional cheaters boost overall OPEC crude production some 400,000 bd over target levels (see Exhibit A.2). To a certain extent, some level of cheating on production quotas is "expected" by most market analysts and would not severely impact OPEC's ability to maintain fixed prices around $18 per barrel. However, if the level of cheating becomes significant, Saudi Arabia may be forced to again act as the cartel's "swing producer" to keep total OPEC production low. While this would appear to help firm prices on the surface, the market will tend to react negatively to such a development, drawing parallels to problems OPEC faced in 1985 just prior to the collapse in oil prices.

To be fair, it is not appropriate to label Iraq a potential "cheater" since Iraq did not sign the recent agreement and has made it clear it will ignore any quota below that of Iran's. Total Iraqi production might reach 2.2 mbd some time in the third quarter, some 600,000 bd higher than the fourth quarter of 1986 production estimates. Much of this gain will be offset by continued Iranian production well below its quota.

Prices

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[6] It should be noted that Iran was the only OPEC member to obtain a higher 1987 quota than it had in late 1986. Perhaps the OPEC delegates realized that Iran's quota was somewhat moot -- Iraq has no intention of letting Iran reach its quota.

The market is still looking for a "natural" range for prices to settle, and this "natural" price range appears to be near the price needed to promote significant new drilling activities in the North Sea and the United States: between $16 and $24/bbl.

The elimination of netback pricing arrangements will tend to firm prices. Fixed prices with quarterly adjustments of production levels and differentials is a perfectly workable solution to OPEC's problems. The speed with which the Merc responded to OPEC's new policies indicated the seriousness with which the paper barrel traders took OPEC. Prices surged almost instantaneously after the OPEC announcement.

The fixed price scheme will probably get the biggest vote of confidence from the Japanese, to whom $18/bbl oil this year feels like around $14/bbl last year owing to the appreciation of their currency. The Japanese are likely to enter into fixed price agreements which last through Spring since the recent price hike has not significantly increased the cost of oil denominated in yen.

Japanese contract volumes will be small relative to total OPEC output, however. Most other buyers are likely to try to postpone contract decisions until some indication of OPEC adherence to fixed prices and lower production is available. The key will be how OPEC member countries respond when crude buyers postpone purchases and start drawing inventories.

In the Base Case scenario official prices crack slightly in spring 1987, with prices reasonably solid through mid-February before starting to slide in March. Second quarter prices are slightly under first quarter levels; some price weakness below $18 is projected between March and May. The second half of the year shows slowly improving oil prices, and by the winter of 87/88 OPEC has successfully converted the market to a fixed price system with a basis of $18 per barrel.[7]

A RAPID PRICE INCREASE SCENARIO

This "price shock" scenario defines a set of plausible market conditions under which prices could quickly surge to around

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[7] The Base Case scenario is projected only through first quarter 1988, and is not a projection of price stability beyond this point. With a price level of $18 per barrel there will be calls from some OPEC members for prices to be pushed even higher.

$30 per barrel (see Exhibit 3). These conditions do not appear to be unusual or unreasonable. They are:

- An increase in consumption of roughly 2.25 percent relative to 1986 levels
- Relatively flat non-OPEC production, with virtually no change in U.S. production and slightly higher production in other Free World countries
- Strict adherence by OPEC to a 15.2 mbd crude oil production quota (16.5 mbd including NGLs) throughout 1987 and into the first quarter of 1988.

The inventory drawdowns necessitated by OPEC production at or around 16.5 mbd through the first quarter of 1988 would be sufficient to send crude oil prices near $30 per barrel. It does not appear that the oil markets are capable of drawing inventories down at the rates shown in Exhibit 3 without bidding up prices quickly.

The degree of OPEC unity needed to keep production around this target certainly exceeds what they have shown in recent years, but would not appear to be unreasonable. Fixed oil prices at or higher than $25 per barrel may in some ways actually be easier for OPEC to target than $18 per barrel. A 10 percent production cut may cause prices to surge roughly 50 percent. Whatever the precise magnitude of the production cut/price increase tradeoff which OPEC can use, it is clear that OPEC can increase oil revenues by restricting production even further than it is already planning. Consequently, the Rapid Price Increase scenario is entirely plausible and could lead to a sustained level of oil prices near $30 per barrel.

A RAPID PRICE DECREASE SCENARIO

In this scenario (see Exhibit A.4), OPEC's recent accord begins to unravel owing to three inter-related reasons:

1. Higher OPEC production from the traditional cheaters and from Iraq's new capacity
2. Reduced confidence from buyers who delay early Spring purchases and draw down inventories in anticipation of lower prices
3. Cheating on fixed prices by OPEC members, which adds incentive for all OPEC members to produce more

Exhibit A.3

Projected Free World Oil Demand, Supply, and Inventories
Scenario 2: Prices Surge to Near $30 per Barrel

	First Quarter 1987	Second Quarter 1987	Third Quarter 1987	Fourth Quarter 1987	First Quarter 1988
DEMAND (millions of barrels per day)					
U.S. consumption	16.0	15.4	15.6	16.0	16.4
Other Free World consumption	32.1	30.9	31.4	32.2	32.8
Government stockpiling	0.1	0.1	0.1	0.1	0.1
Inventory buildup (1)	0.0	0.0	0.0	0.0	0.0
Total Free World demand	48.2	46.4	47.1	48.3	49.3
SUPPLY (millions of barrels per day)					
U.S. production	9.8	9.7	9.7	9.7	9.8
Other non-OPEC production (2)	17.2	17.2	17.3	17.3	17.5
Inventory drawdown	3.0	1.4	1.8	3.4	4.2
Net communist exports	1.2	1.8	2.0	1.6	1.5
OPEC production	17.0	16.3	16.3	16.3	16.3
Total Free World supply	48.2	46.4	47.1	48.3	49.3
Net U.S. oil imports	5.2	5.3	5.3	5.2	5.2
Crude Oil Prices (3) (US dollars per barrel)					
U.S. West Texas Intermediate	17-19	18-20	20-24	22-27	25-30
U.K. Brent Blend	17-19	17-19	19-23	21-26	23-28
Arab Light	16-18	16-18	17-21	19-24	22-27

(1) Includes floating stocks and oil in transit

(2) Free World only. Includes production of crude oil and natural gas liquids, other hydrogen and hydrocarbons for refining feedstock, and refinery processing gains.

(3) Quarterly average of spot prices

Source: Hagler, Bailly & Company based on information supplied by the IEA, the EIA, the API, and the trade press.

Exhibit A.4

Projected Free World Oil Demand, Supply, and Inventories
Scenario 3: Prices Drop to Near $10 per Barrel

	First Quarter 1987	Second Quarter 1987	Third Quarter 1987	Fourth Quarter 1987	First Quarter 1988
DEMAND (millions of barrels per day)					
U.S. consumption	16.0	15.5	15.5	15.8	16.1
Other Free World consumption	32.0	30.7	31.1	31.8	32.2
Government stockpiling	0.1	0.1	0.1	0.1	0.1
Inventory buildup (1)	0.0	0.5	2.8	1.3	0.3
Total Free World demand	48.1	46.8	49.5	49.0	48.7
SUPPLY (millions of barrels per day)					
U.S. production	9.8	9.7	9.6	9.5	9.4
Other non-OPEC production (2)	17.2	17.2	17.2	17.2	17.3
Inventory drawdown	1.9	0.0	0.0	0.0	0.0
Net communist exports	1.2	1.8	2.0	1.6	1.3
OPEC production	18.0	18.2	20.7	20.7	20.7
Total Free World supply	48.1	46.9	49.5	49.0	48.7
Net U.S. oil imports	5.6	6.0	6.9	6.8	6.8
Crude Oil Prices (3) (US dollars per barrel)					
U.S. West Texas Intermediate	15-19	14-18	10-14	9-14	10-14
U.K. Brent Blend	15-19	13-17	9-13	8-13	9-13
Arab Light	14-18	10-14	8-12	7-12	8-12

(1) Includes floating stocks and oil in transit
(2) Free World only. Includes production of crude oil and natural gas liquids, other hydrogen and hydrocarbons for refining feedstock, and refinery processing gains.
(3) Quarterly average of spot prices

Source: Hagler, Bailly & Company based on information supplied by the IEA, the EIA, the API, and the trade press.

> and reduces buyers' confidence, leading in turn to a desire to dump inventories and yet lower prices.

In this scenario, OPEC unity dissolves and production rises quickly to mid-1986 levels. As Exhibit A.4 indicates, the jump in OPEC oil production to over 20 mbd quickly swamps the market, sending prices down to 1986 levels.

This scenario is similar to actual market conditions during late-1985, early-1986 when OPEC production surged and prices plummeted. Consequently, there is a precedent for such a price plunge. It, too, can lead to a long period of consistent oil prices -- this time at or near $10 per barrel.

THE POSSIBILITY OF CYCLICAL OIL PRICES

While it has never been easy to predict OPEC policies or responses to market conditions, the three scenarios outlined are entirely plausible. The price of oil is in a precarious balance between firm, fixed prices near $30 per barrel and a return to spot prices around $10 per barrel. In the Base Case scenario OPEC is reasonably successful in converting to a fixed price scheme centered on an $18 per barrel price level. The second scenario shows that by cutting production OPEC can increase oil revenues. Because OPEC found the production discipline needed to maintain crude production around 15.0 mbd during the second and third quarters of 1985, there is an historical precedent for OPEC to follow this policy. The last scenario, a price plunge to near $10 per barrel, is easily envisioned and constructed. It would merely entail a return to late-1985 market conditions.

It is easy to envision a scenario in which oil prices "cycle" between $10 and $30 per barrel, staying at the upper and lower levels of that price range for periods which may exceed a year. Previous experience indicates that a long-term equilibrium exists at neither $10 nor $30 per barrel. At $10 per barrel, OPEC has too much incentive to regain control of the market to increase prices. And at $30 per barrel, non-OPEC suppliers and consumers react to push prices down. And while a long-term equilibrium price may or may not exist, as is often postulated, between $16 and $24 per barrel, there is no reason to think that prices are not inherently "stable" cycling around this equilibrium. Cyclical pricing is a plausible possibility for oil because prices are cyclical in many commodity markets.

APPENDIX B

THE VOLATILITY OF OIL PRICES AND OTHER COMMODITY PRICES

In Appendix A it was shown that oil prices could easily jump to $30 per barrel or fall to $10 per barrel, even if no supply disruptions occur. Oil is a commodity whose price is volatile, and a price collapse can lead to bankruptcies among domestic producers. It is important for Federal policymakers to be aware of the economic impact of oil price shocks, to determine whether some form of government intervention is appropriate. Before the issue of economic impact is analyzed, however, it is important to address another issue: What is so special about oil? Isn't it possible to take any commodity traded in world markets and show that domestic producers could be put out of business by a price collapse? Are oil prices really more volatile than other commodity prices?

In this chapter an indicator of world crude oil prices is selected, and the volatility of this indicator is compared with the volatility of other commodity prices and price indices in U.S. markets over the 1960-1984 period. The analysis suggests that:

- In 1980 the world oil price indicator was 11 times the 1972 level. None of the other commodities selected for study shows a comparable range of price variation in the 1960-1984 period.[1]
- In the 1960-1984 period, world oil prices show a better correlation with gold and silver prices than with other non-fuel primary commodity prices. This is due to the non-commodity role of precious metals. Gold, and to a lesser extent silver, are demanded to a large degree because they are a store of value. Demand, and thus price, for precious metals increases whenever key economic indicators or global events suggest a period of inflation, recession, or general instability. One of

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[1] Commodities that have shown such price volatility have been gold (especially in the presence of political instability or unrest) and silver (during the attempted cash corner).

those key indicators is the price of oil, at least since 1973.

- The possibility of a return to the 1972 real price level is a major price risk for the oil industry that has no parallel in other commodity markets.

These results suggest that oil is somewhat "special" because domestic oil producers can claim to be more vulnerable to extreme price swings than producers of other globally traded primary commodities, with the exception of precious metals.[2] Proposals to mitigate oil price shocks cannot be dismissed on the grounds that oil is "just another commodity" -- that the case for intervention in the oil market is no stronger than the case for any intervention in any other commodity market. While this finding alone does not provide a justification for Federal intervention in oil markets, it strengthens the case for intervention.

THE HYPOTHESIS THAT OIL IS "JUST ANOTHER COMMODITY"

The primary purpose of the analysis described in this appendix is to test the hypothesis that oil is "just another commodity" as far as price behavior is concerned. While the effect of oil price swings on the performance of the U.S. economy is profound, as the discussion in Chapter 1 shows, the magnitude of these economic impacts is related to the magnitude of energy-related expenditure rather than the rate of oil price change. This appendix addresses the question whether the pattern of oil price fluctuations is unusual relative to other commodity price fluctuations.

The thesis that petroleum prices are volatile because petroleum is a commodity has been stated clearly by Arlon Tussing:

> Just as the whole economy is cyclical, the energy industries are cyclical, and they are normally much more volatile than the rest of the economy. ...Oil and gas are commodities, and their markets are commodity markets with powerful similarities to the

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[2] In theory a better measure of the "profit squeeze" on domestic producers would be the margin between prices and costs. There may be "cost shocks" as well as "price shocks;" but cost fluctuations are beyond the scope of this report.

> markets for goods such as soybean, fishmeal, and copper.[3]
>
> ... petroleum is a commodity, and like almost every widely-traded crude material, its markets are inherently cyclical.[4]

In general the volatility of commodity prices is attributable to the following factors:

Weather (affecting agricultural and energy commodities)
Speculation associated with inventory holdings
Changes in cartel behavior and the unity of cartels
Strikes and work stoppages
Wars, revolutions, and terrorist attacks
Changes in government regulation (quotas, tariffs, etc.)
Cyclical changes in demand affecting minerals (i.e., a business cycle)
Resource exploration and discovery (affecting energy and minerals)
Creation of substitutes via technological change.

While all of these factors affect oil prices, none are unique to oil. In qualitative terms it is fair to say that oil is "just another commodity" as far as price behavior is concerned. Crude oil and petroleum products are traded on exchanges along with pork bellies and orange juice.

If oil is to be distinguished from other commodities, the distinction must be quantitative, e.g., based on measures of price volatility.[5] To develop quantitative measures of the volatility of oil prices and other commodity prices it is necessary to answer two questions:

1. Which commodities should be included in a comparison between the volatility of oil prices and the volatility of other commodity prices?

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[3] Arlon Tussing, "Energy Prices in the Long-Term: A New Era of Competition," paper presented before a conference on "The Outlook For Natural Gas," Arlington, VA, October 15-16, 1984, p. 2.

[4] Arlon Tussing, "World Oil-Market Outlook and United States Energy Policy" prepared testimony before the U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Fossil and Synthetic Fuels, March 6, 1986, p. 2.

[5] In Chapter 1 a quantitative distinction was drawn on the basis of the dollar volumes (and the magnitude of macroeconomic effects) associaated with price fluctuatuions.

2. Which indicators and which data sources should be used to measure price volatility?

The following discussion begins by addressing these two questions, and concludes with a review of the analytical findings.

WHICH COMMODITIES SHOULD BE INCLUDED IN A COMPARISON WITH OIL?

What, precisely, is a commodity? There are perhaps three alternative definitions that may be used:

1. **The classical definition:** A "primary commodity" is a good that is traded in world markets and falls into one of four categories -- food, beverages (coffee, tea, and cocoa), agricultural raw materials, and metals (other than precious metals). Primary commodities must be raw materials produced by agriculture and mining. This is the narrowest definition of commodity, but it may be considered the "classical" definition; it is used by the International Monetary Fund.[6]

2. **The marketplace definition:** A commodity is any good traded on an exchange, other than a currency. Oil, lumber, and precious metals (gold, silver, palladium and platinum) are commodities. If a good is traded in large volumes on a "spot" delivery basis subject to standardized terms and conditions and quality specifications, it is a likely candidate for a commodity exchange; once prices are posted by the exchange, the good becomes a commodity.[7]

3. **The market indicator definition:** A commodity is any good for which spot or short-term prices per unit are publicly available and are considered by both buyers and sellers to be meaningful indicators of market condi-

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[6] International Monetary Fund, Primary Commodities: Market Developments and Outlook, May 1986, pp. iii-iv.

[7] Under this definition, a posted price offered by an individual seller or broker is no substitute for a posted price on an exchange. Coal is not traded on an exchange floor, even though there is a spot market for coal. There are a great many petroleum brokers and traders in the United States, and an exchange is not necessary for trading activity (see, for example, the Petroleum Marketers' Handbook compiled by the editors of Oil Buyers' Guide).

tions. Under this definition, coal, natural gas, and other goods for which brokers and traders quote unit prices are considered commodities.

Among the three definitions of "commodity" listed above, only the classical definition of "primary commodity" excludes oil.

Yet another definition -- the futures definition -- may be noted. In the context of a study of price volatility, commodities may be grouped together with currencies and Treasury bonds under the general heading of "items traded in futures markets." The Wall Street Journal listing of "Futures Prices," for example, contains prices for items in six sectors: grains and oilseeds, livestock and meat, food and fiber, metals and petroleum, wood, and financial. In Wall Street Journal price postings the following exchanges are treated as a group:

Amex Commodities Corp.
Chicago Board of Trade
Chicago Mercantile Exchange
Commodity Exchange, New York
Chicago Rice & Cotton Exchange
Coffee, Sugar & Cocoa Exchange, New York
New York Cotton Exchange
International Petroleum Exchange of London
International Money Market at CME, Chicago
Kansas City Board of Trade
London International Financial Futures Exchange
MidAmerica Commodities Exchange
Minneapolis Grain Exchange
New York Futures Exchange (a unit of the New York Stock Exch.)
New York Mercantile Exchange
Philadelphia Board of Trade
Winnipeg Commodity Exchange.

From a business perspective, all of the items traded on these exchanges may be grouped together. Futures for light sweet crude oil, heating oil no. 2, and unleaded gasoline are among the items traded on the New York Mercantile Exchange.

Among the various definitions described here, the marketplace definition is best suited to an analysis of price volatility. The "market indicator" definition is too broad because it encompasses markets in which competition is not strictly on the basis of the seller's price. The "futures market" definition is also too broad because it includes currencies and financial instruments, for which supply and demand are not constrained by resource scarcity.

WHICH INDICATORS AND WHICH DATA SOURCES SHOULD BE USED TO MEASURE PRICE VOLATILITY?

To compare the volatility of crude oil prices with the volatility of other commodity prices it is necessary to do the following:

- Select a price averaging period (daily, weekly, monthly, or yearly)
- Select a method for adjusting prices for overall inflation
- Select an indicator of world crude oil prices
- Select a data source (or sources) for other commodity prices
- Select a measure of price volatility.

The choice of price averaging period for this analysis is dictated by the purpose of the analysis: measuring the frequency of major price fluctuations (the ones that are most likely to threaten the financial stability of producers). The assumption will be made that producers can ride out day-to-day and week-to-week price fluctuations easily. Monthly or quarterly price swings may weed out financially weaker producers, but well-managed firms should be threatened only by a string of several bad quarters. While quarterly price data would be ideal for this analysis, annual data are much simpler to obtain and analyze. Annual data were therefore selected.

The adjustment of prices for inflation helps to distinguish price changes attributable to supply and demand conditions in a particular market from price changes attributable to inflation in the economy as a whole. To adjust prices for inflation, the implicit price deflator for Gross National Product was used. This deflator is a reasonable indicator of overall cost inflation faced by U.S. producers of commodities sold in U.S. markets.[8] The focus of this analysis is on prices facing U.S. producers because the purpose of this analysis is to support an evaluation of U.S. policy alternatives.

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[8] By contrast, the real commodity price index developed by the International Monetary Fund (IMF) uses the United Nations' deflator for the value of manufactured exports of "developed market economies." International Monetary Fund, Primary Commodities: Market Developments and Outlook, May 1986, p.2.

The choice of currency -- U.S. dollars -- affects the volatility of each commodity price index. If this analysis were focused on international policy initiatives (e.g. International Energy Agency or World Bank initiatives), it would be appropriate to use several commodity price indices rather than U.S. dollar indices alone. The IMF routinely computes a primary commodity price index against the U.S. dollar, pound sterling, Deutsche Mark, French franc, Japanese yen, and Special Drawing Right (SDR).[9] The index is most volatile when computed against the French franc and least volatile when computed against SDRs.

For an indicator of world crude oil prices, the annual average spot price of Mideast Light Crude, 34 degrees API, was selected for this analysis. A time series going back to 1960, based on Petroleum Intelligence Weekly data, is published by the Energy Information Administration.[10] For the 1979-1982 period the spot price of any Mideast crude is a better indicator of market conditions -- a better measure of the price facing non-OPEC producers on the world market-- than the Official Price.[11]

Because domestic crude oil markets were subject to import quotas and price controls over much of the 1960-1981 period, the annual average wellhead price of domestic crude oil is less volatile over the 1960-1984 period than the annual average spot price of Mideast Light Crude. From a policy analysis perspective, however, the relevant basis for measuring the volatility of prices facing U.S. producers is an international spot price.

The primary data source selected for commodity prices is a Department of Commerce publication, Business Statistics 1984. This publication contains annual price averages and price indices for selected commodities for the 1960-1984 time period.[12] It may be inferred from the relatively small number of commodity price indicators in this publication that these data series are considered by the Commerce Department to be superior "business indicators." For pre-1977 gold prices, however, it was necessary to use a metals industry trade publication.[13]

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[9] International Monetary Fund, Primary Commodities: Market Developments and Outlook, May 1986, p. 3,6.

[10] U.S. Department of Energy, Energy Information Administration, Annual Energy Review 1985, DOE/EIA-0384(85), p. 257. "Mideast Light Crude" prices primarily reflect Arabian Light Crude Oil prices.

[11] Philip K. Verleger, Jr., Oil Markets in Turmoil (Cambridge, Mass.: Ballinger, 1982), pp. 15-20.

For each commodity the measure of price volatility selected for this analysis is the ratio of the real price in a given year to the real price in 1972.[14] In other words, an inflation-adjusted annual price index was computed for each commodity, using an index value of 1 for 1972. The year 1972 was selected, rather than a subsequent year, to better display 1973-1985 oil price trends graphically (i.e., to avoid "compressing" the price rise of 1973-74). Another reason for selecting 1972 is that global commodity prices were relatively stable in the 1960-1971 period, but volatile in 1972-1980.[15]

FINDINGS

The computed real price indexes are illustrated in Exhibits B.1 through B.9. The graphs in Exhibits B.4 through B.9 are plotted on the same vertical scale in order to show the relative magnitude of price variations. The trends shown in these exhibits show that:

- Over the 1960-1985 period the price of Mideast Light Crude has varied more than the average wellhead price of domestic crude oil. The apparent discrepancy in price indices is explained by the fact that the spot price of Mideast Light Crude in 1972 was \$1.82 per barrel while the average wellhead price of domestic crude was \$3.39 per barrel.

- In 1980 the real spot price of Mideast Light Crude was 11 times the 1972 level. None of the other commodities

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[12] For copper, lead, and zinc, the indexes are based on U.S. producer prices, which prior to the late 1970's exhibited less volatility than spot market prices.

[13] American Metal Market, Metal Statistics 1982 (New York: Fairchild Publications, 1982).

[14] To perform the analysis efficiently, Lotus 123 software was used; unfortunately, this software does not permit graphs to be prepared with a logarithmic scale on the vertical axis.

[15] International Monetary Fund, Primary Commodities: Market Developments and Outlook, May 1986, p. 1.

Exhibit B.1

Arab light crude vs. domestic crude

Real price indexes (1972=1)

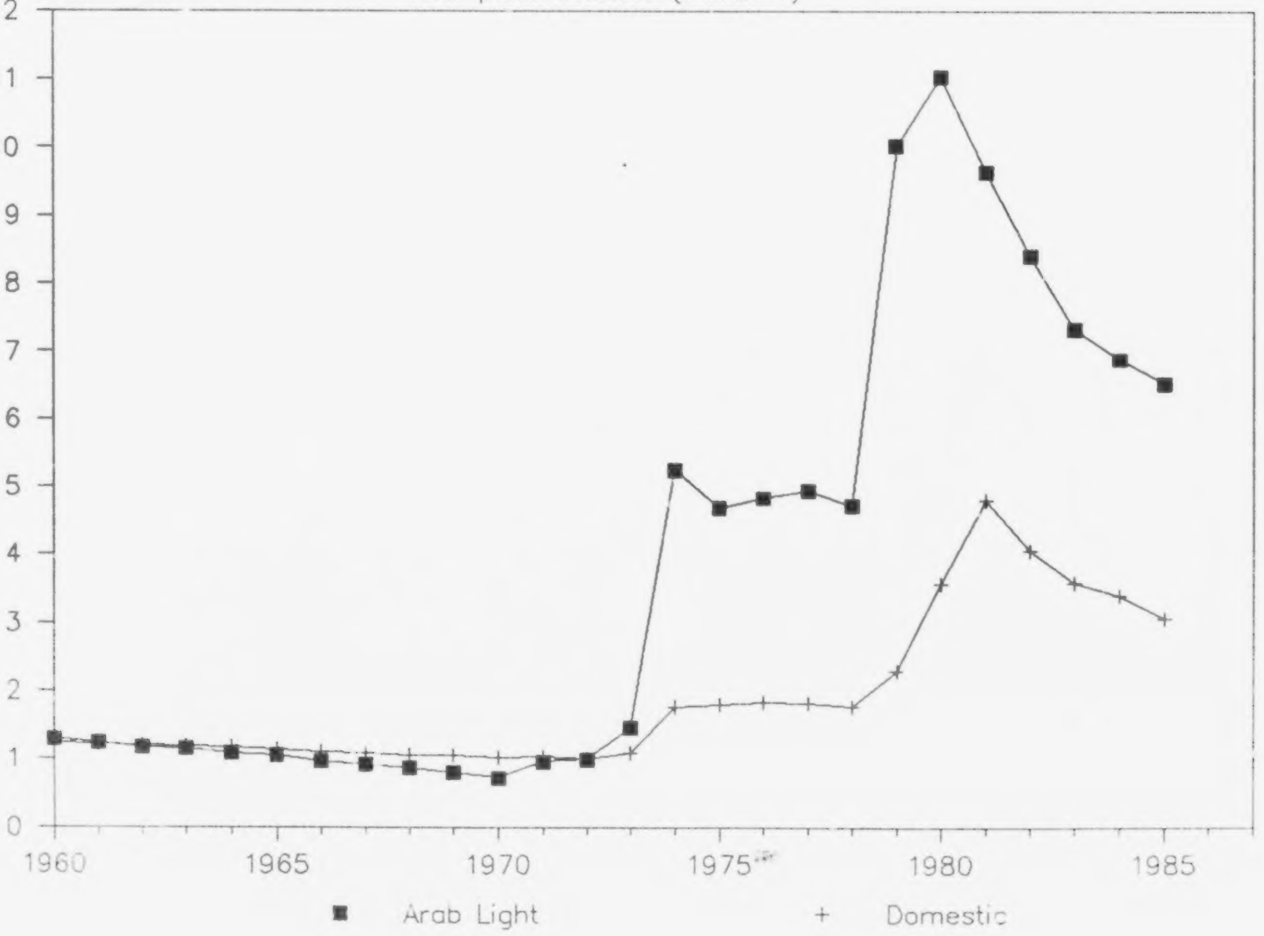


Exhibit B.2

Gold and silver

Real price indexes (1972=1)

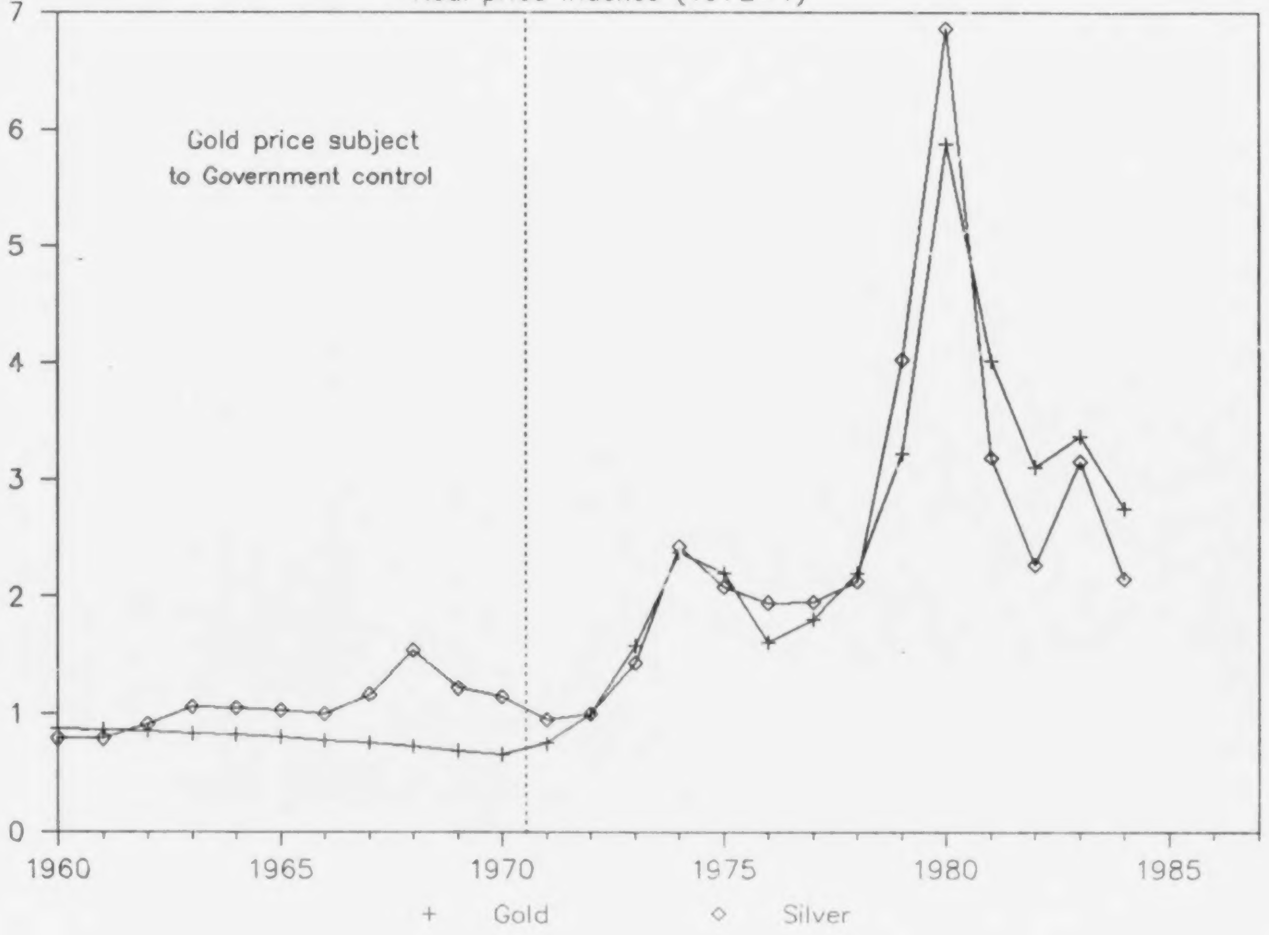


Exhibit B.3

Arab Light crude, gold, and silver

Real price indexes (1972=1)

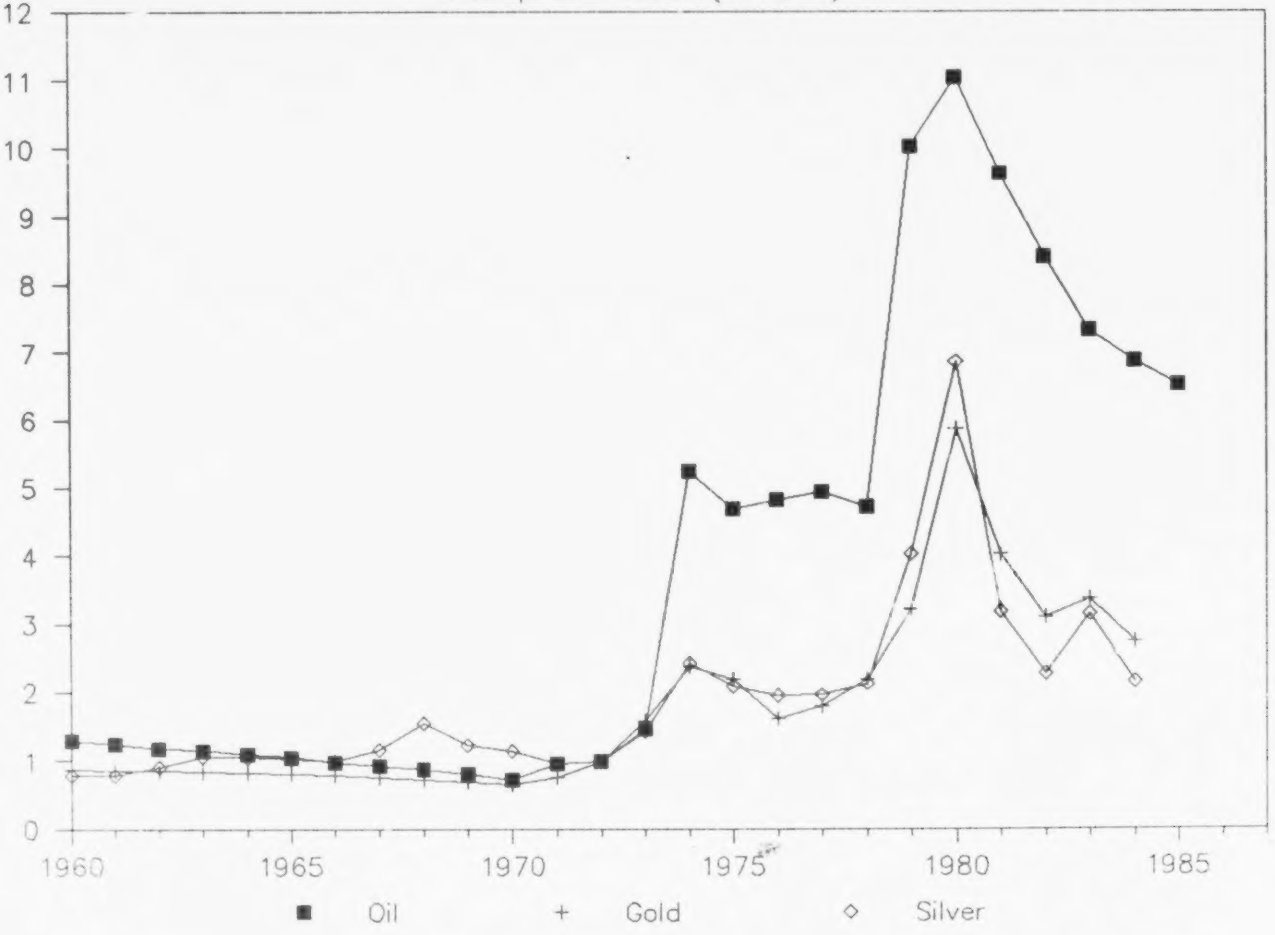


Exhibit B.4

Steel scrap and aluminum

Real price indexes (1972=1)

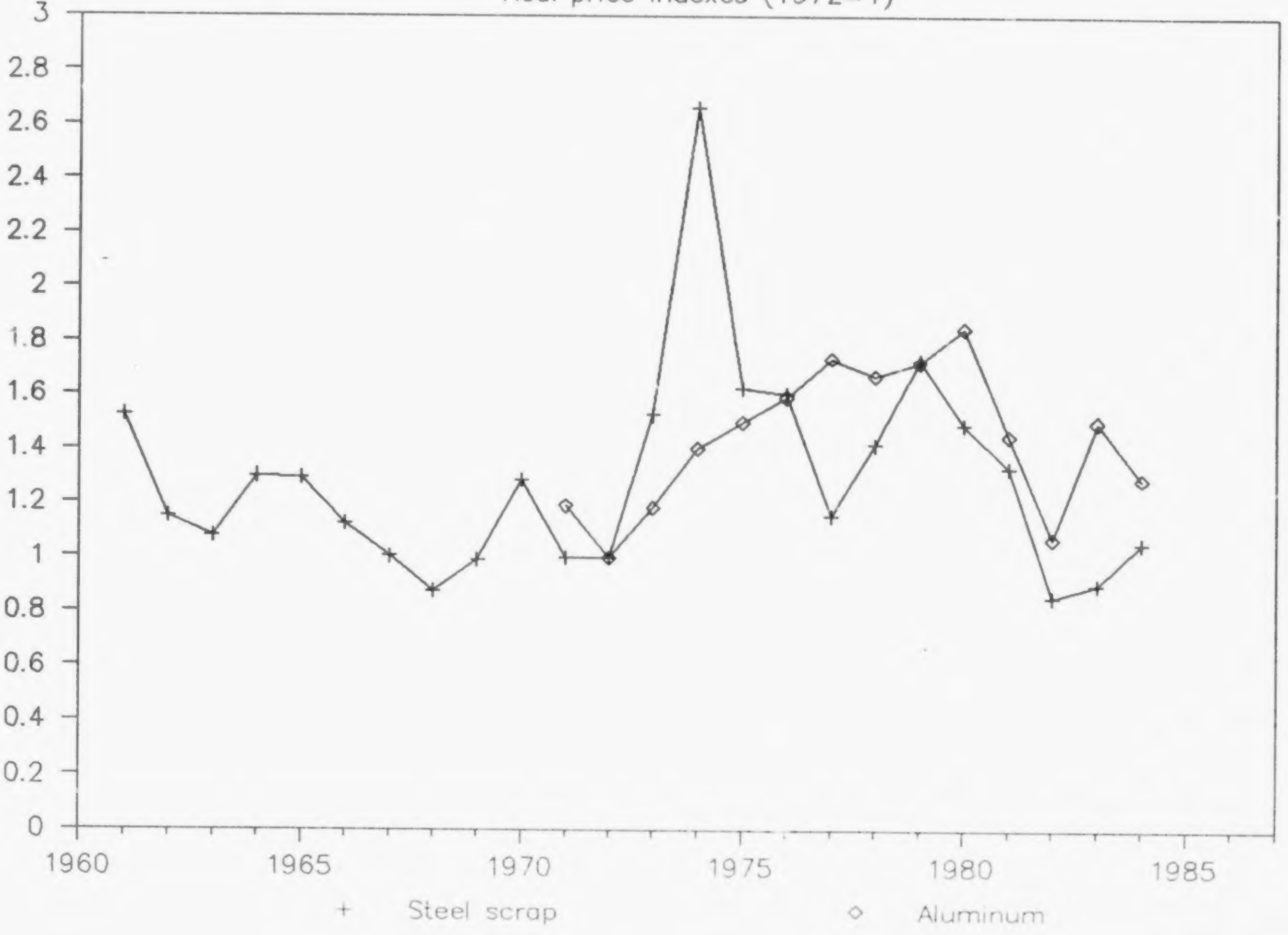
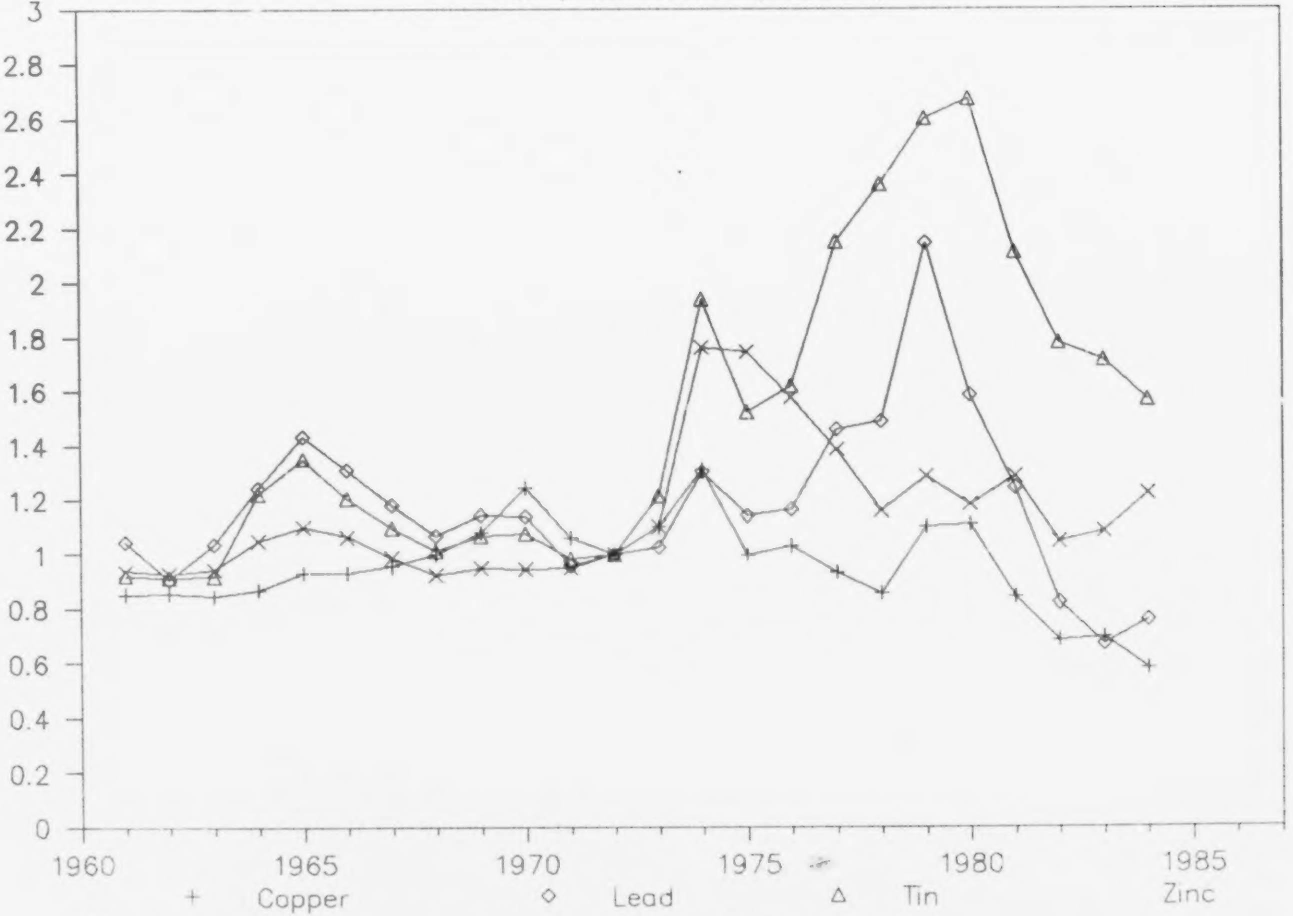


Exhibit B.5

Copper, lead, tin*, and zinc

Real price indexes (1972=1)



*For much of this period, the price of tin was significantly influenced by the buffer stocks and policies of the International Tin Council.

Exhibit B.6

Lumber

Real price indexes (1972=1)

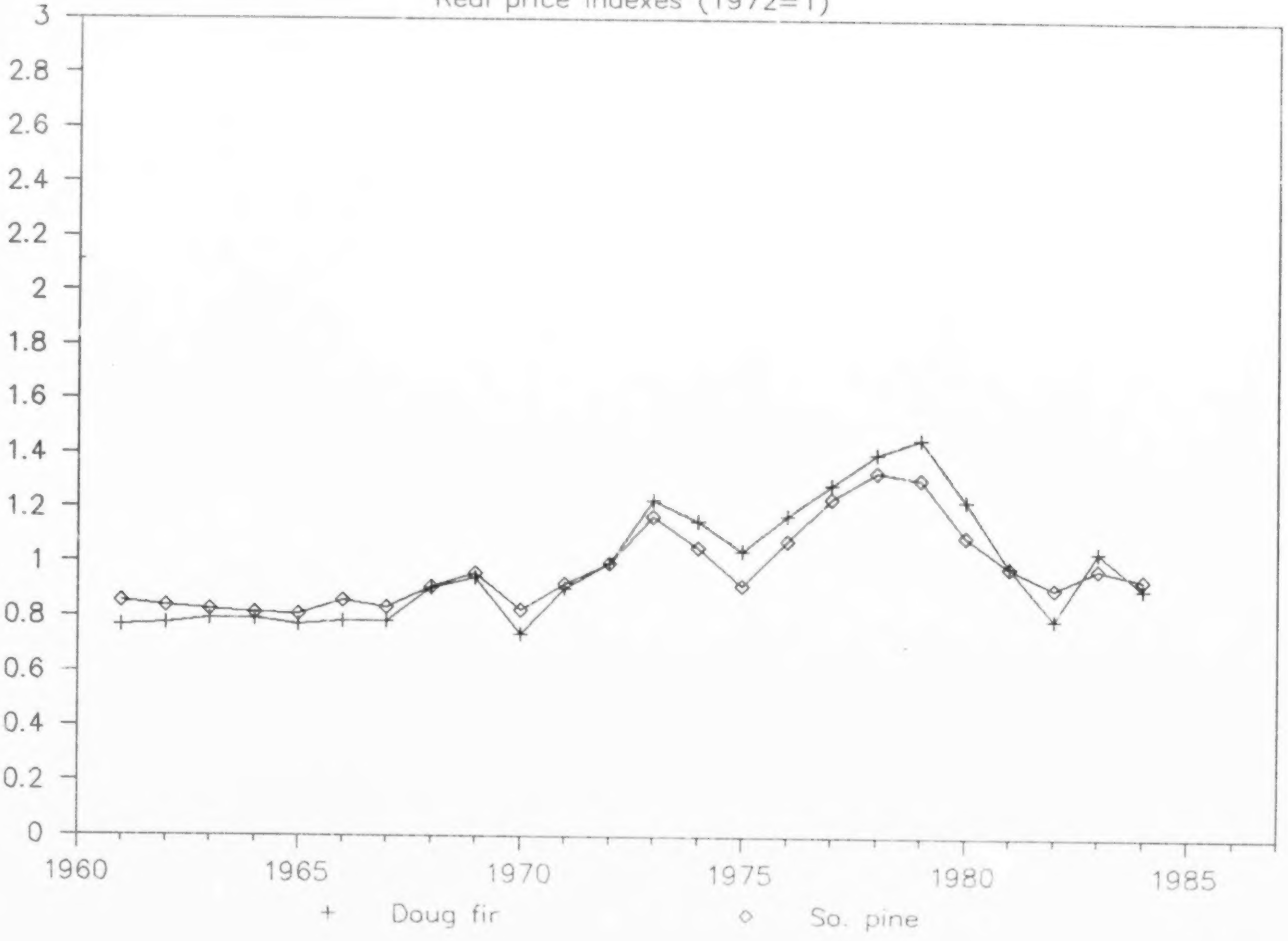


Exhibit B.7

Corn, rice, and wheat

Real price indexes (1972=1)

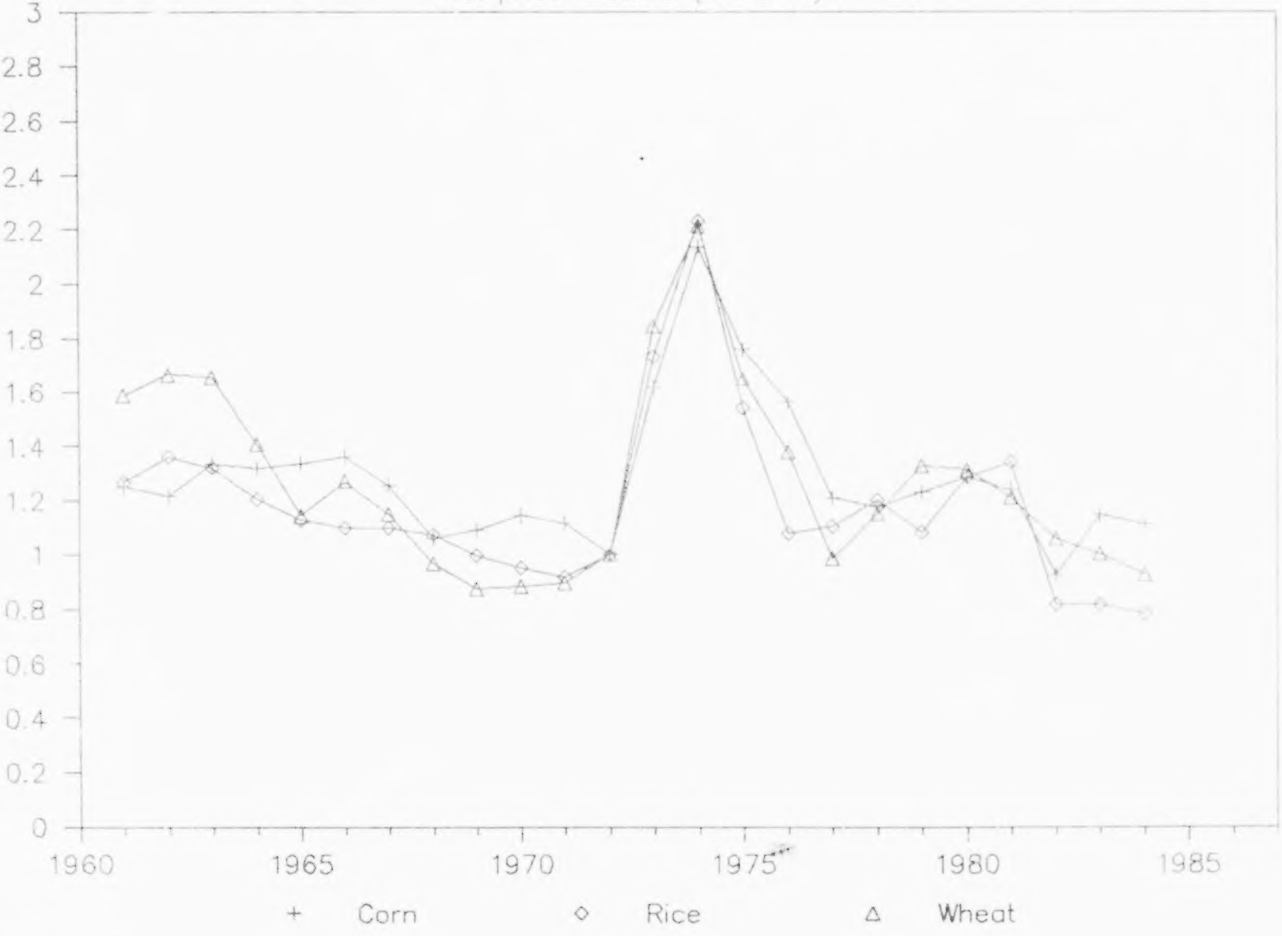


Exhibit B.8

Beef, pork, and chicken

Real price indexes (1972=1)

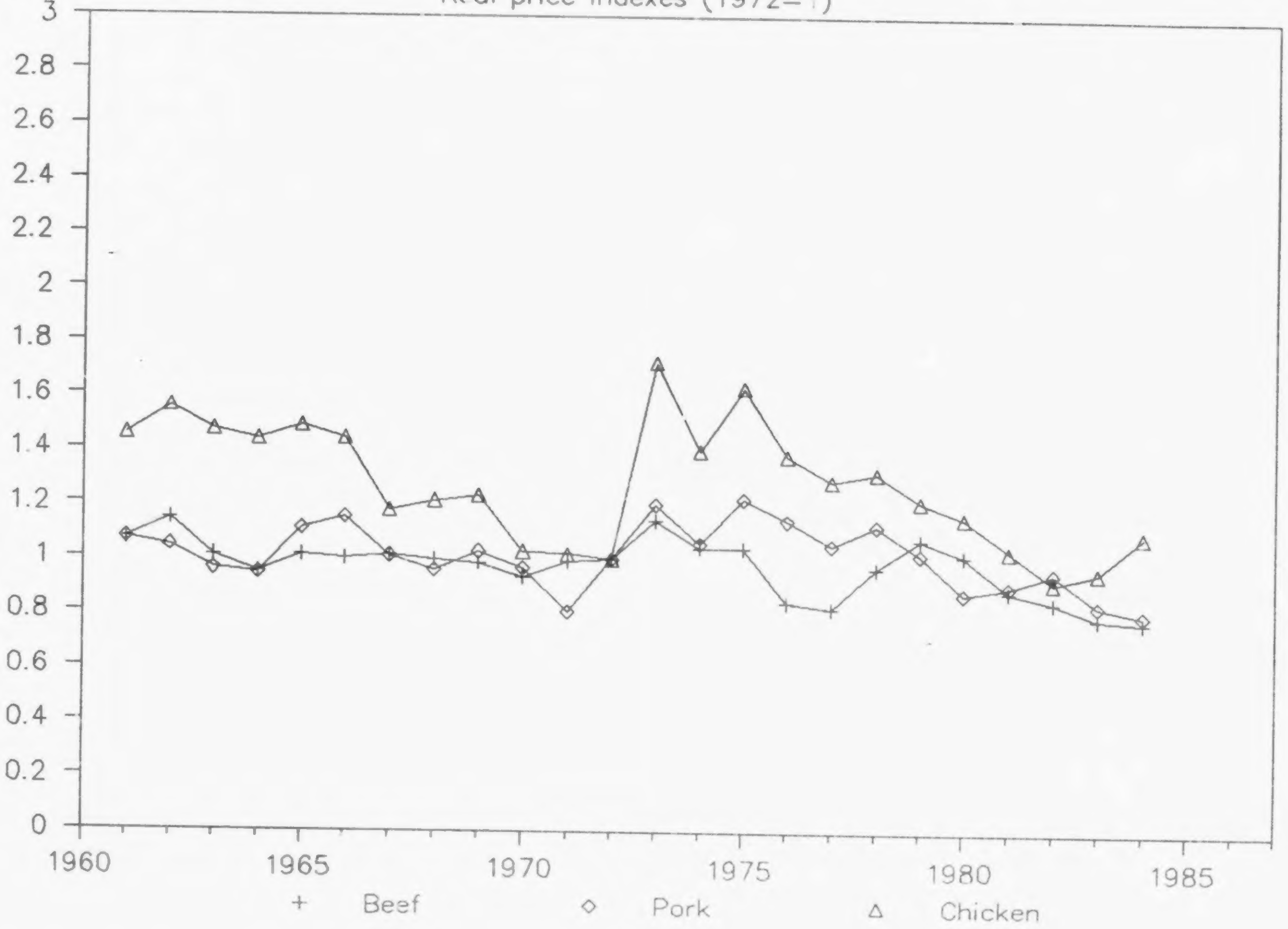
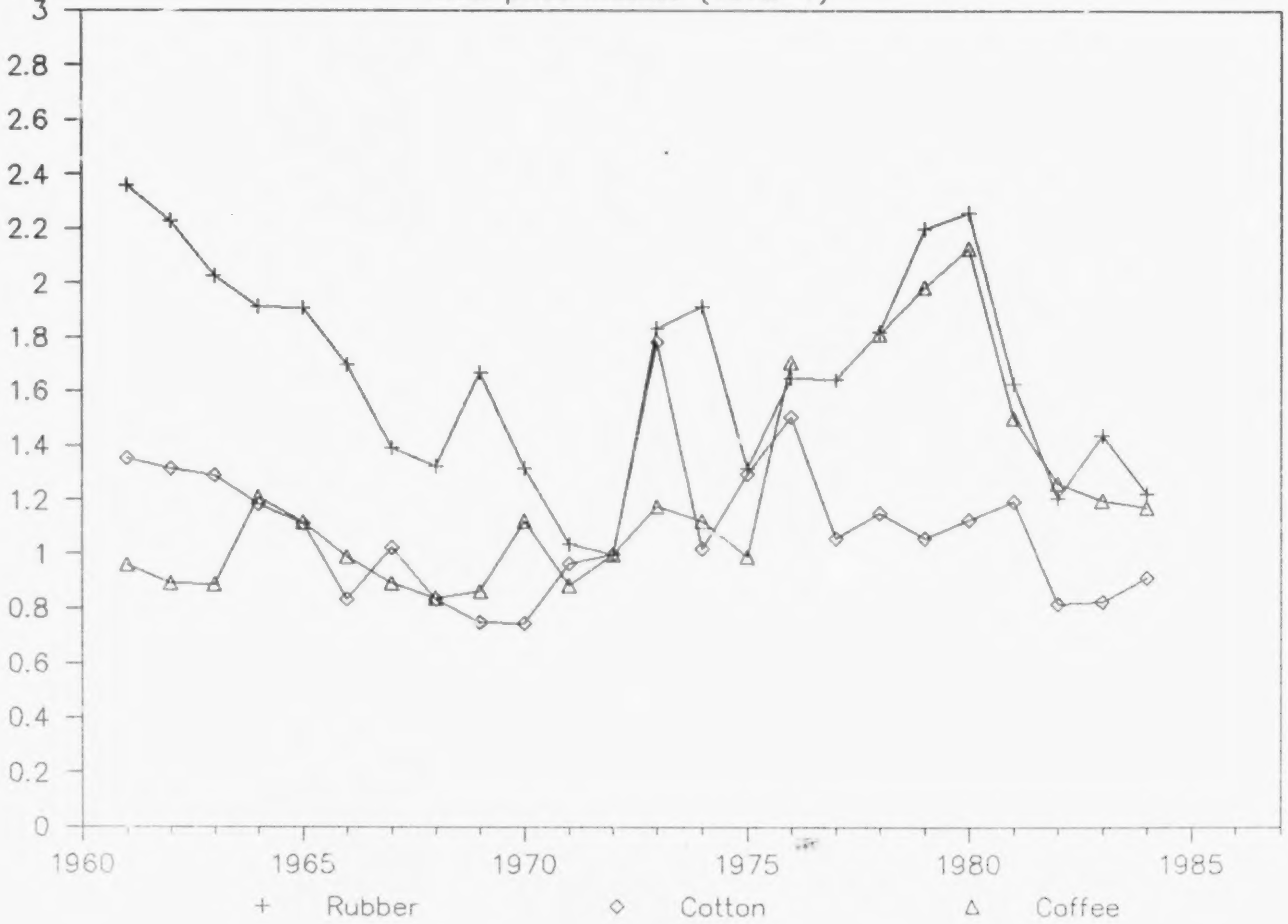


Exhibit B.9

Rubber, cotton, and coffee

Real price indexes (1972=1)



selected for study shows a comparable range of price variation in the 1960-1984 period.

- In the 1960-1984 period, world oil prices show a better correlation with gold and silver prices than with other non-fuel primary commodity prices. In its price behavior oil appears to be a form of currency or precious metal.

- The possibility of a return to the 1972 real price level is a major price risk for the oil industry that has no parallel in other commodity markets. A major source of volatility in oil prices is the fact that pre-1974 prices are much lower than post-1974 prices -- a pattern duplicated only by gold and silver.[16]

Despite these findings, it is important to recognize that the prices of many primary commodities (e.g., copper, lead, tin, zinc, corn rice, wheat, rubber, cotton, and coffee) are highly volatile. Why doesn't this price volatility adversely affect the economy, just as oil price volatility affects the economy?

The basic answer to this question is that petroleum product prices tend to move in unison while prices of various agricultural commodities and precious metals are more likely to move independently. Moreover, no other commodity is as pervasive in or important to the economy as petroleum, and thus volatility in the other commodities will not have such broad affects on the economy.

The preceding analysis of price volatility was focused on individual commodities rather than commodity groups. It is reasonable to assume that the price volatility of the "petroleum and products" aggregate exceeds the price volatility of the "agricultural products" aggregate even though these aggregates are comparable in magnitude. In the U.S. trade balance, the dollar volume of agricultural exports was roughly equivalent to the dollar volume of petroleum imports in 1984-1985.[17] It is the magnitude of energy expenditures, as well as the volatility of oil prices, that makes the price of oil a critical parameter affecting the performance of the U.S. economy.

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[16] If there were no possibility of a return to pre-1974 price levels (adjusted for inflation), oil price volatility might be measured against 1974-1984 data only. The long-run marginal cost of oil is still very low, however, and the threat of a price "war" creates a major source of price risk for oil producers.

[17] Petroleum and products represented 17.2 percent of the value of U.S. imports in 1984 and 14.4 percent of the value of imports in 1985; agricultural products represented 17.8 percent of the value of merchandise exports in 1984 and 14.1 percent in 1985. See U.S. Department of Commerce, Survey of Current Business 66,11 (November 1986), p. S-17.

APPENDIX C

THE RECENT DECLINE IN U.S. EXPLORATION ACTIVITY

The oil price crash of 1986 caused a sharp decline in exploration activity and in oil industry employment. The purpose of this appendix is to describe the market's response to the recent drop in oil prices. The following questions are addressed:

- What are the causes of the decline in U.S. exploration activity?
- How severe was the decline in exploration activity in 1986?
- Is U.S. crude oil production falling?
- Does the level of imports appear to rise (on a monthly basis) as the price of oil falls?
- What "caused" the increase in imports in 1986--increasing demand, declining production, or increasing stocks of crude oil and petroleum products?

The findings of this appendix may be summarized as follows:

- The decline in drilling activity in 1986 is explained by the limitations of the domestic resource base, the drop in oil prices, and the prospect of future "price wars" among OPEC members.
- While the annual average rig count dropped in 1986 to 49 percent of the 1985 level, the July count was only 35 percent of the 1985 level. While it is impossible to precisely compute the rig count necessary to yield reserve additions that will replace production when prices are $18/bbl, a rough estimate would be that the "reserve replacement" level is about three times the average 1986 rig count.
- From January 1986 to December 1986, domestic crude oil production fell 773,000 b/d, or 8.5 percent. It is too soon to tell whether production will stabilize or

continue to decline, if prices stabilize at the levels prevailing in early January 1987.

- The monthly level of imports is more sensitive to expected changes in price than to the absolute level of prices. Imports rose in late 1986 to supply oil for inventory buildup.
- The increase in imports in 1986 was caused by short-term increases in domestic crude and product inventories, and a long-term trend of decreasing domestic production.

These points are discussed in detail below.

FACTORS CAUSING DECREASED EXPLORATION ACTIVITY IN THE U.S.

The recent drop in exploration activity in the U.S. is an indicator that low oil prices will result in a long-term trend toward increased reliance on imports. If the inflation-adjusted price of imported oil remains low relative to prices in the 1974-1985 period, a sharp decline in domestic exploration activity (evidenced by a decline in the active rig count) will lead to a drop in U.S. production that will be made up by increased imports rather than alternate fuels or energy conservation.

Different oil market analysts have different explanations of the decline in U.S. drilling activity that occurred in 1986. Two hypotheses may be distinguished:

- The efficient market hypothesis -- the hypothesis that U.S. markets allocate resources efficiently. According to this view, the percentage of domestic demand met by domestic production can be explained by rational investment behavior under competitive and efficient land, capital and labor markets in the U.S. The "efficient market" hypothesis is that oil price expectations must be revised downward, based on the events of 1986, and under these lower price expectations it simply is not economic to maintain U.S. crude oil production at 8.7 million barrels per day, although it is economic for petroleum demand to rise slightly. Domestic exploration and production activity fall because various prospects and recovery operations become uneconomic at lower prices.
- The inefficient market hypothesis -- the hypothesis that U.S. markets fail to allocate resources efficiently. Under this view, the outlook for oil price is suffi-

> ciently favorable, and the cost of finding and producing oil in this country is sufficiently low, that the 1986 decline in exploration activity is too sharp to be explained simply by the efficient market hypothesis. Under this view, the oil industry may be constrained by imperfect capital markets, unreasonably pessimistic price expectations, and expectations that government regulations will be relaxed. Perhaps the risk of a price war creates a capital market imperfection; perhaps firms are too pessimistic about future oil prices; perhaps firms are postponing investments in anticipation of changes in tax law, Federal leasing policy, or natural gas regulation.

To defend the efficient market hypothesis it is not necessary to estimate the cost of finding and producing incremental supplies of domestic oil, or to speculate about oil firms' price expectations and risk preferences.

The U.S. appears to be experiencing a long-term trend toward increasing dependence on oil imports. The U.S. reserve/consumption ratio -- the ratio of proved reserves of crude oil and natural gas to petroleum product consumption -- shows a long-term declining trend (see Exhibit C.1). The two bright spots are 1970, when Alaska's North Slope reserves were recorded, and 1980-1981, when oil consumption fell in response to price increases. These data suggest that the international competitiveness of U.S. exploration and production prospects has declined over several decades, and that U.S. resources have been depleted more rapidly than those of most other oil exporting countries. If this trend were caused by inefficiency in U.S. markets, the sources of inefficiency would have to persist for decades.

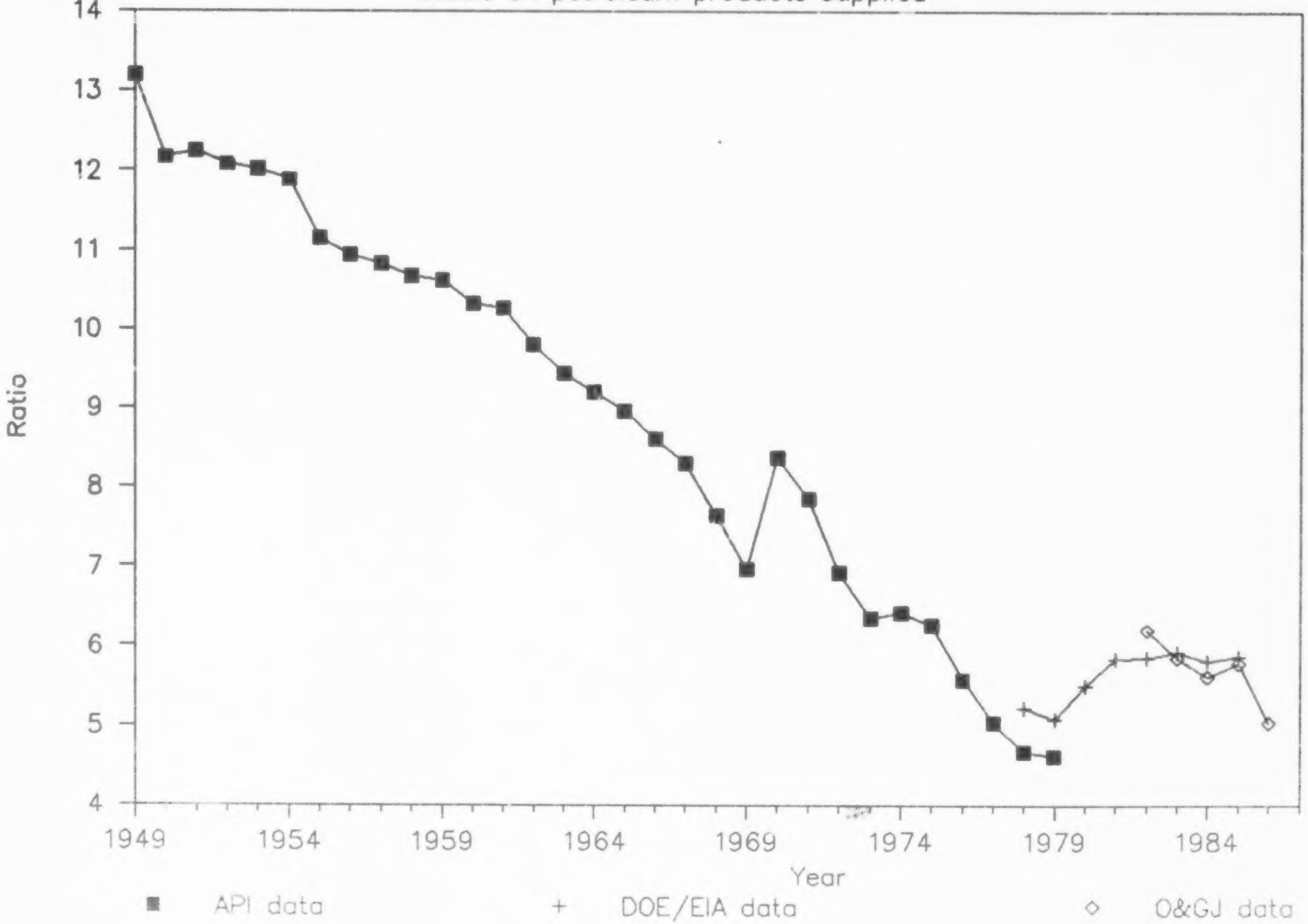
Under the efficient market hypothesis, the decline in drilling activity in 1986 is explained by the limitations of the domestic resource base, the drop in oil prices, and the prospect of future "price wars" among OPEC members. More precisely, the decline in drilling is explained by four factors:

- The global distribution of resources. Data on production per well, lifting cost per barrel, reserve/production ratios, and discoveries per exploratory well show that the petroleum resources of Mideast oil producing nations are less expensive to develop than the remaining petroleum resources of the U.S. Due to geological factors, the cost of producing crude oil from existing reserves and the cost of finding new reserves are much higher in the U.S. than in the Mideast oil producing

Exhibit C.1

U.S. oil reserve/consumption ratio

based on petroleum products supplied



nations. It is reasonable to assume, therefore, that the crude oil resource base of the U.S. becomes less competitive with the crude oil resource base of Mideast nations as the price of oil falls. For a given decline in oil prices the number of "good" drilling prospects falls proportionately more in the U.S. than in the Mideast. As the U.S. has depleted its natural endowment of oil resources, other countries have gained a competitive advantage in world crude markets.

- **The possibility of price collapse.** The only plausible objective of OPEC meetings must be to elevate the price of oil above the level that would prevail in a perfectly competitive market. Any oil producer who believes that rises in oil prices are attributable to OPEC must also believe that the failure of OPEC nations to reach agreement must lead to a fall in oil prices (a price "collapse" that may be either intentional or unintentional). The expectation of very low oil prices is consistent with the the perception that OPEC nations will occasionally or frequently fail to reach agreement.

- **Divisions within OPEC.** There have been several indications of disagreement among OPEC members. The war between Iran and Iraq has obviously strained OPEC. In the fall of 1985 the government of Saudi Arabia announced that Saudi production would be increased as a result of the failure of OPEC nations to adhere to their quotas and to set reasonable quotas for Saudi production.

- **Recent price trends.** Oil prices did, in fact, fall in 1986 following the Saudi production increase. In January 1986 the acquisition cost of imported crude oil began to fall sharply, reaching $10.91 per barrel in July 1986. Domestic oil prices remain low relative to 1980-1985 levels.

While these points alone do not define a rationale for government intervention in the marketplace, they define an economic problem that cannot be resolved by restoring the "health" of the U.S. oil industry. Even if domestic oil companies were profitable, efficiently run, unimpeded by government regulation, capable of anticipating future oil prices, and equipped with a work force and a capital stock as productive and efficient as any in the world, the domestic share of oil supply would fall under a "low oil price" scenario. There is nothing "wrong" with U.S. oil companies, relative to their international counterparts. Like the domestic timber industry, the uranium industry, or the copper industry, the domestic oil industry is constrained by resource scarcity relative to some of its international competitors.

To compare the level of oil prices today with the level of oil prices in the 1970s it is necessary to show prices in 1986 dollars (see Exhibit C.2). The drop in crude oil prices in 1986 brought the average refinery acquisition cost (RAC) of domestic crude oil back to the 1974-1978 level. An oil price of about $18 per barrel today is significantly higher than the 1970-1973 price level, adjusted for inflation. Domestic exploration activity today is below the 1970-1973 level, however. In this context the depression in exploration activity is worse than one would "expect" on the basis of a change in oil prices alone.

INDUSTRY RESPONSE TO THE OIL PRICE CRASH OF 1986

To gauge the seriousness of the U.S. oil import problem, it is necessary to review the recent performance of U.S. oil markets. Several questions may be addressed:

- How severe was the decline in exploration activity in 1986? Did drilling activity rebound?
- Is U.S. crude oil production falling?
- Does the level of imports appear to rise (on a monthly basis) as the price of oil falls?
- What "caused" the increase in imports in 1986--increasing demand, declining production, or increasing stocks of crude oil and petroleum products?

The following discussion of these issues is based on the latest available data from the Energy Information Administration.

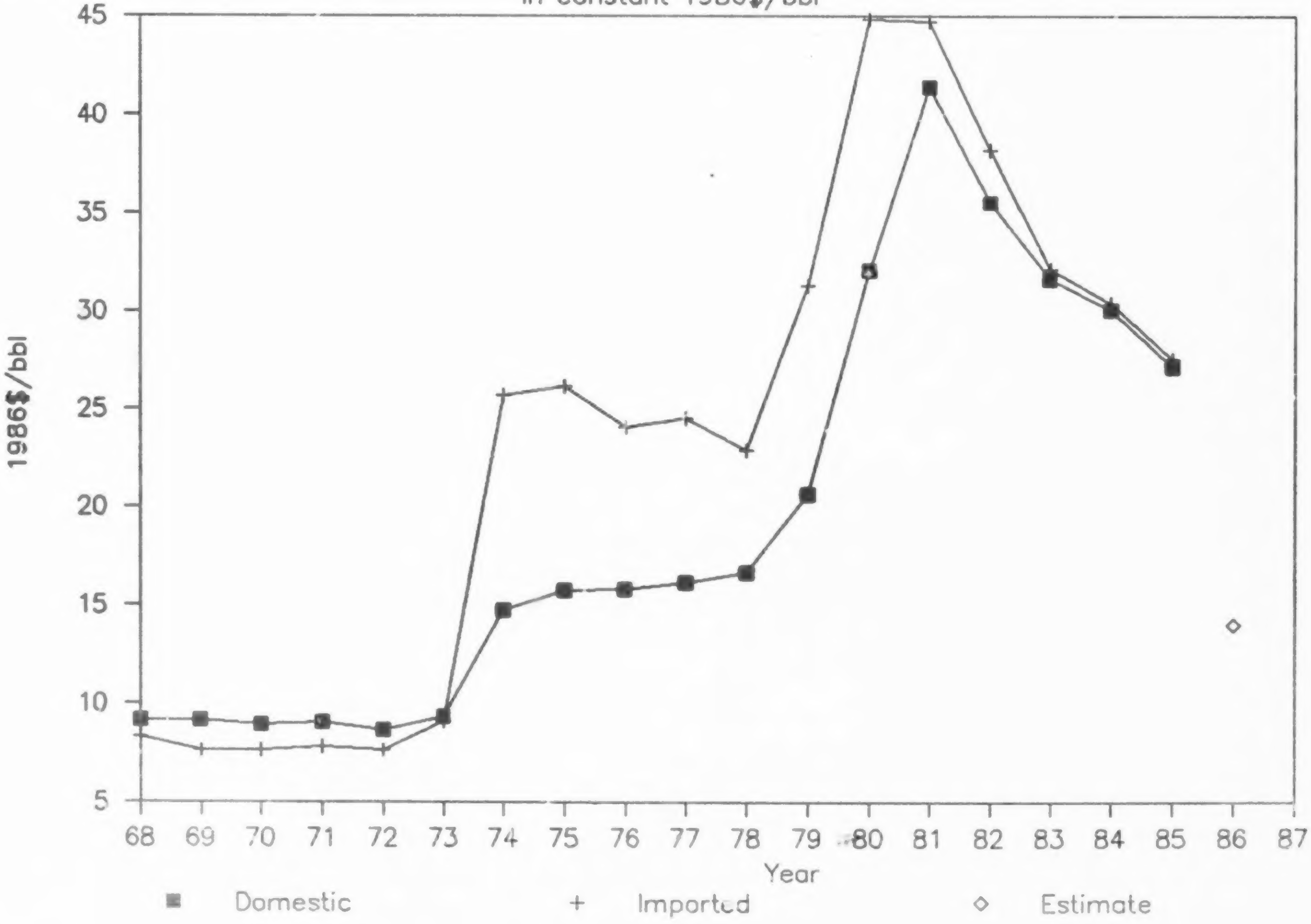
THE DECLINE IN DRILLING ACTIVITY

Several statistics can be used to measure exploration activity. There are two monthly indicators of exploration activity: the operating rotary rig count (estimated by Hughes Tool Company) and the seismic crew count (reported by the Society of Exploration Geophysicists). While the rotary rig count includes rigs involved in drilling development wells as well as exploratory wells, it is a good measure of exploration activity because the ratio of total well completions to

Exhibit C.2

Refiners' acquisition cost of crude oil

in constant 1986$/bbl



exploratory wells is relatively stable. Among the quarterly indicators of exploration activity are the number and footage of exploratory well completions (estimated from the API/IPAA surveys), the number and footage of new-field wildcat well completions (also from API/IPAA), and the level of capital and exploration expenditures by companies with publicly traded stock (reported in quarterly reports to shareholders). Among the annual indicators of exploration activity are exploration expenditures of selected major energy companies (from the DOE/EIA survey of Financial Reporting System companies) and total exploratory and development drilling expenditures (from the Joint Association Survey). More current (but perhaps less precise) capital expenditure estimates are published annually by the Oil & Gas Journal. All of these indicators are highly correlated with each other. The best "advance" indicator of well completions and well footage is the active rotary rig count.

In 1986 the annual average rig count dropped below 1000 and fell to 49 percent of the 1985 level (see Exhibit C.3). While the rig count in 1985 was only half the 1981 level, the drilling boom that peaked in 1981 was not typical of the drilling activity of the last three decades. Because revisions have represented a large share of crude oil reserve additions over the last decade, and because a large portion of drilling is devoted to nonassociated gas prospects, it is impossible to make a simple calculation of the level of drilling necessary to sustain the 1985 production level, i.e., to maintain crude oil reserve additions at 3 billion barrels per year. A very rough estimate of the reserve replacement level, assuming $18 per barrel oil, would be 3000 rigs, or three times the 1986 rig count. This estimate is based on the assumption that revisions to reserves will fall sharply if prices stabilize at $18 per barrel.

The monthly rig count bottomed out at 686 in July 1986 and began rising steadily in the months that followed (see Exhibit C.4). The July 1986 rig count was only 35 percent of the 1985 average. These data suggest that the monthly rig count is very sensitive to oil prices, and that the time lag between a drop in world oil prices and a drop in U.S. exploration activity is very short. At the low level of drilling activity in effect today, it appears that a "rebound" to at least 2000 active rigs can quickly be achieved as soon as the economics are favorable.

Exhibit C.3

Indicators of U.S. drilling activity

1949–1986

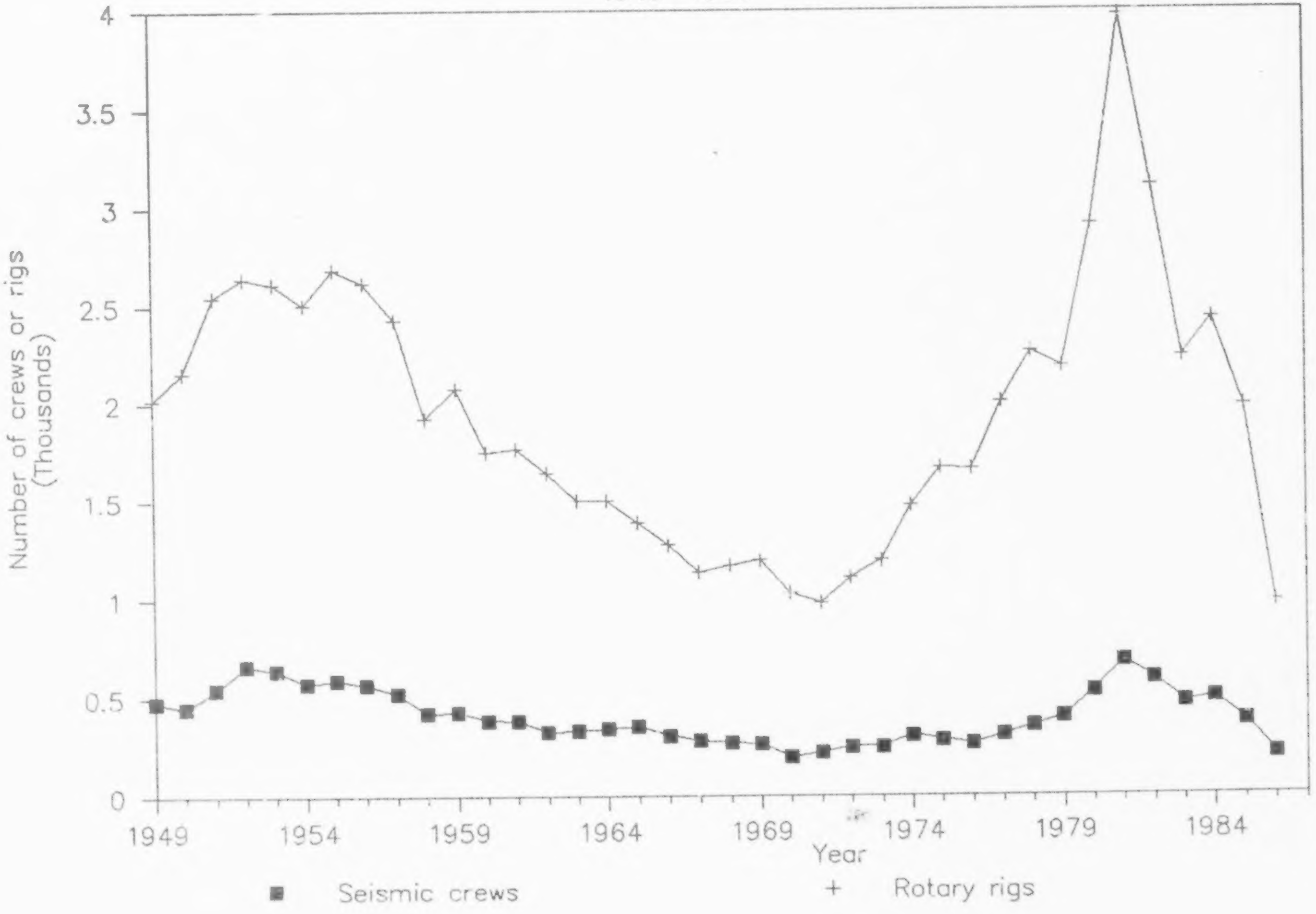
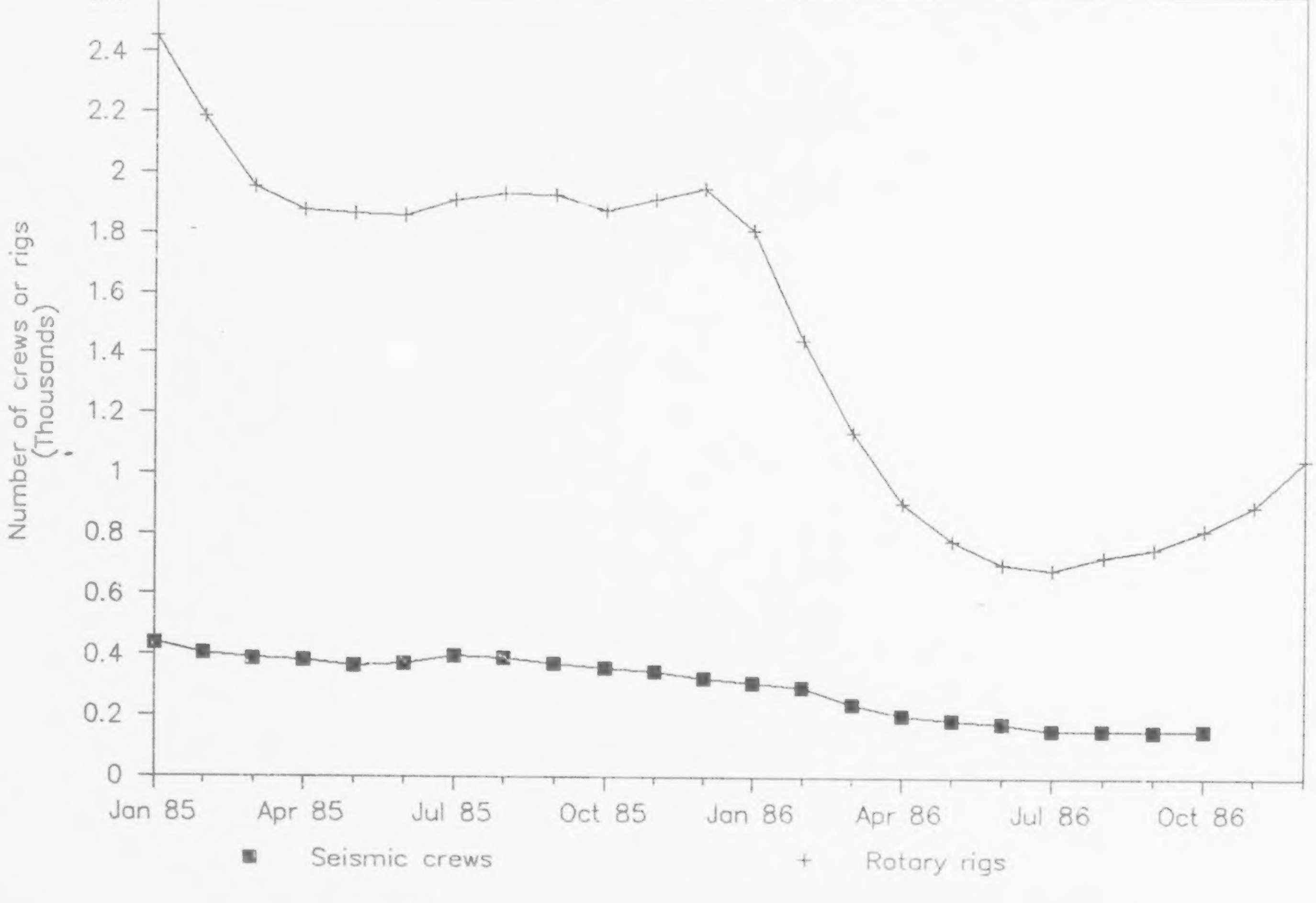


Exhibit C.4

Indicators of U.S. drilling activity

1985–1986, by month



Perhaps the best annual measure of exploration activity is the number of exploratory wells completed.[1] In its July 28, 1986 drilling forecast the Oil and Gas Journal estimated that 6,187 exploratory wells would be drilled in 1986 (see Exhibit C.5). This represents a 59 percent reduction from the 1984 level (15,128 exploratory wells) and represents "the lowest forecast since the accompanying historical tabulation was set up."[2]

Because development drilling is less risky than exploration drilling, one would expect total drilling to be affected less severely by the oil price drop. The total of exploratory and development well completions reported in the Monthly Energy Review for 1986 is 47 percent below the comparable 1984 figure.

CRUDE OIL PRODUCTION TRENDS

While the trend in monthly crude oil production is not perfectly smooth, it is clear that a downward trend began in February 1986, when oil prices fell (see Exhibit C.6). The annual rate of decline is about 700,000 to 800,000 b/d, and it is not clear that the decline stopped at the end of the year. At a price of $18/bbl, an 800,000 b/d jump in oil imports increases the current account deficit by $5.2 billion per year.

In part, the decline in production may be attributable to a decline in enhanced oil recovery, secondary recovery, and stripper well operation -- high cost production activities that are unaffected by drilling activity and reserve discoveries. These production activities (and reserve revisions) may rebound if oil prices rebound. Many wells will not be worth restarting once they are shut in, however.

The fact that production did not rise in late 1986 as prices rose suggests that a significant portion of the production decline is attributable to a decline in the number of successful oil well completions (particularly exploratory oil well completions). According to the Oil & Gas Journal drilling survey, the number of exploratory wells dropped 44 percent in 1986 (from 12,498 wells in 1985 to 6,987). A

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[1] Another measure would be the total footage of exploratory drilling.

[2] Neither the DOE Monthly Energy Review nor the Petroleum Supply Monthly report exploratory well completions or footage.

Exhibit C.5

U.S. exploratory well completions

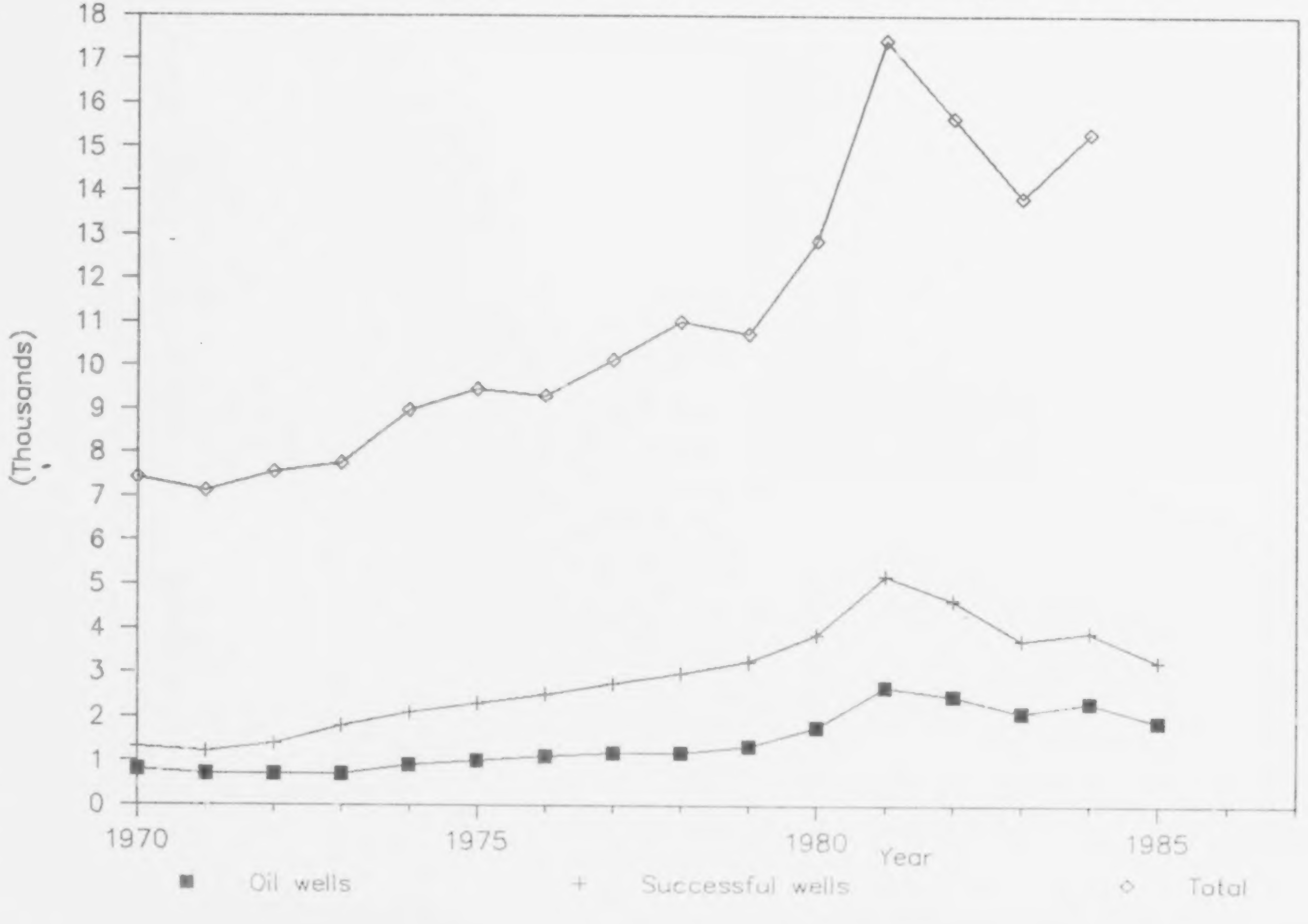
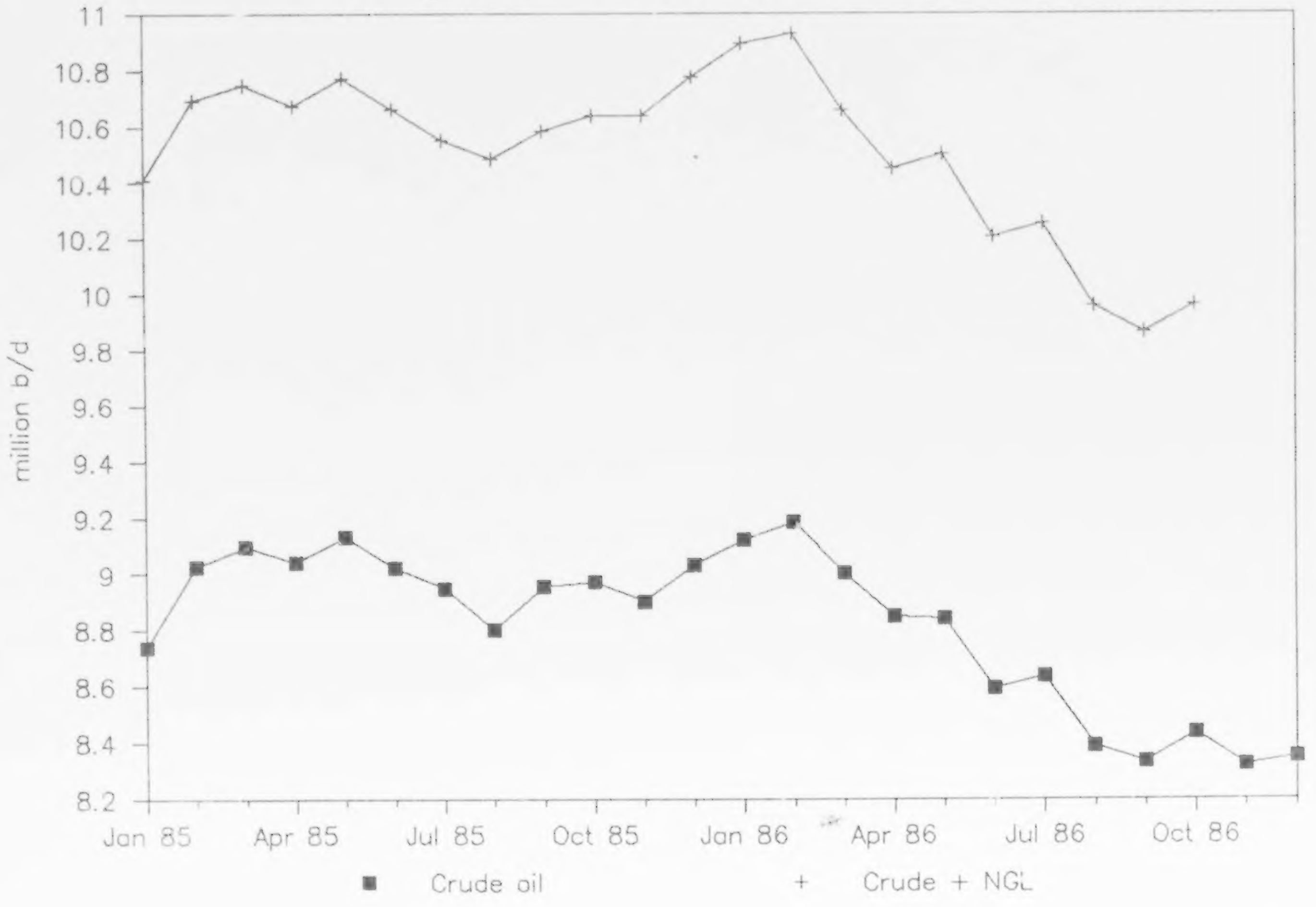


Exhibit C.6

U.S. petroleum production



proportionate drop in reserve discoveries may be assumed (if discoveries are concentrated in small and medium-sized fields). It will be very difficult to "make up" for the shortfall in reserve discoveries; to do so, future drilling will have to exceed the level associated with replacement of annual production, or another giant oil field such as the North Slope must be discovered. The drilling boom that peaked in 1981 merely postponed a decline in U.S. production. Unless oil prices exceed their 1981 level or government support for exploration is provided in the future, any recent production loss caused by inadequate exploration activity may be considered almost permanent.

THE RELATIONSHIP OF IMPORTS TO PRICE CHANGES

The relationship of imports to price changes is complicated by the economics of crude oil and petroleum product inventories. If petroleum demand were not seasonal and inventories were negligible, one would expect domestic production to rise and fall with oil prices. For a given change in oil prices, the change in imports would equal the change in domestic demand less the change in domestic supply.

With inventories in the picture, however, the effect of price changes is more complex. Inventories tend to shrink when prices are falling and expand when prices are rising. When oil buyers anticipate a price increase, they will purchase oil for inventory; when they anticipate a price decrease, they will minimize the volume of purchases by selling off their inventory. When prices are low, oil consumers concerned about security of supply (e.g. the Federal government, owner of the Strategic Petroleum Reserve) may increase the number of days' supply in inventory because the cost of energy security is relatively low. In a period of stable prices, inventories of furnace oil (and crude oil) tend to grow in the fall and shrink in the spring.

It is reasonable to expect imports to be more sensitive to inventory changes than domestic production. For the U.S. producer it is attractive to use imports as the "swing" source of supply in order to maintain a high capacity utilization on domestic oil wells.

One of the complications of any analysis of inventory changes is the fact that end users can alter their inventories to speculate on oil price changes. Residential customers, for example, may try to fill their oil furnaces when heating oil prices bottom out. From the government's viewpoint, short-term changes in consumption patterns are difficult to distinguish from inventory changes.

Aggregate data for 1986 show that it is hard to distinguish long-term increases in U.S. import dependence from short-term fluctuations associated with changes in inventories. When the price of crude oil began to fall in early 1986, imports went down (see Exhibit C.7). At this point the market apparently anticipated lower inventories due to lower prices, as well as the normal seasonal drop in inventories. Once the price of crude oil hit bottom, inventories grew and imports began to rise rapidly. These data suggest that imports will fall again if oil prices stabilize in early 1987.

THE RELATIONSHIP OF IMPORTS TO DEMAND, PRODUCTION, AND STOCK CHANGES

An increase in imports must be associated with at least one of the following components of the U.S. petroleum account balance:

- an increase in inventories of crude oil or petroleum products

- an increase in demand (e.g., petroleum product supplied by refiners)

- a decrease in domestic production of crude oil and natural gas liquids (NGL)

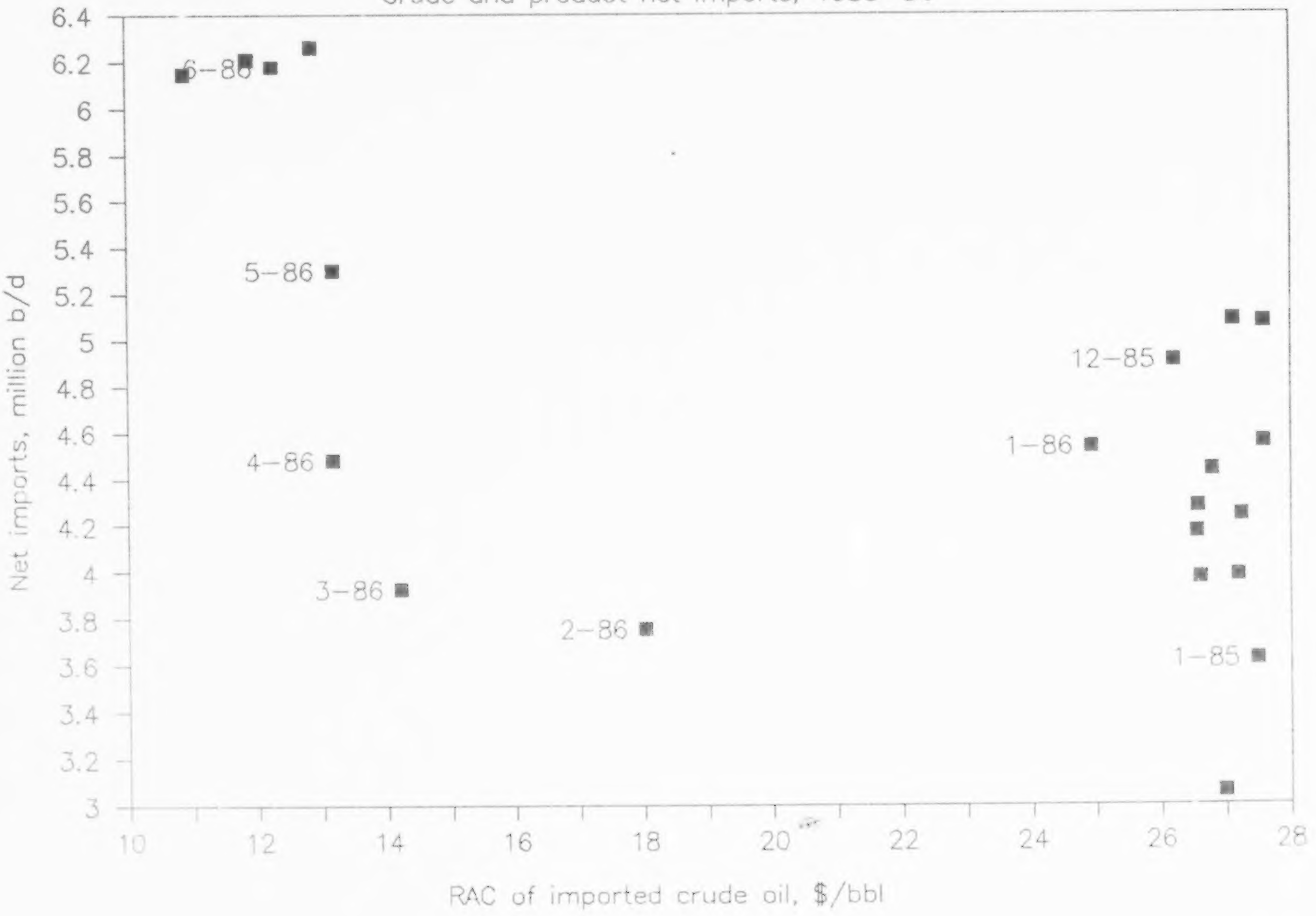
- an increase in either of the two "balancing items" used by EIA to reconcile crude oil supply and demand -- crude oil production for which refinery purchases are not identified ("crude oil unaccounted for") and refinery inputs for which product outputs are not accounted for ("refinery gain").

The meaning of an increase in the balancing items is of course unclear. In the EIA accounts all crude oil and petroleum products are measured in barrels rather than heat content, so the "refinery gain" is in part a method of accounting for differences in the density of crude oil and petroleum products. The sum of the balancing items is reduced significantly when all crude and product flows are measured by heat content, in barrels of domestic crude oil equivalent (i.e., units of 5.8 million Btu). An increase in the adjusted sum of the balancing items may reflect a change in the proportions of natural gas and oil used at refineries, a change in the thermal efficiency of refinery operations

Exhibit C.7

Relationship of imports to oil price

Crude and product net imports, 1985–86



(caused by a change in the product mix, for example), or a measurement error. Monthly "crude oil unaccounted for" may be due to measurement error (e.g., booking of crude oil production and purchase in different months).

To represent changes in imports, demand, and production graphically, it is necessary to compute changes relative to some arbitrary reference levels. Any two of these reference levels determine the third. To analyze 1986 data it is convenient to use an import level of 5 million b/d, a domestic production level of 10 million b/d, and a demand level of 15 million b/d. The use of these reference levels is not intended to indicate that an import level of 5 million b/d is "normal" over a longer time frame.

The major factor explaining the increase in imports in 1986 is the change in inventories (see Exhibit C.8).[3] The change in domestic production is a less important factor but it shows a consistent trend over time. The change in demand does not show a long-term trend so clearly. The variability of the balancing items is large enough to question the accuracy of all the other data (especially the January 1986 data). The only clear indicator of a long-term increase in dependence on imports is the decline in domestic production. The high level of additions to inventories in late 1986 explains why the share of demand attributable to imports rose by more percentage points than the share of demand attributable to domestic production (see Exhibit C.9). The 1986 trend in imports as a share of demand is somewhat misleading, as a long-term indicator.

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[3] In Exhibits C.8 and C.9 domestic demand is measured in barrels of domestic crude oil equivalent in order to minimize the size of the "balancing item" required to fully account for domestic demand.

Exhibit C.8

Explanation of changes in oil imports

relative to a 5000 boe/d import level

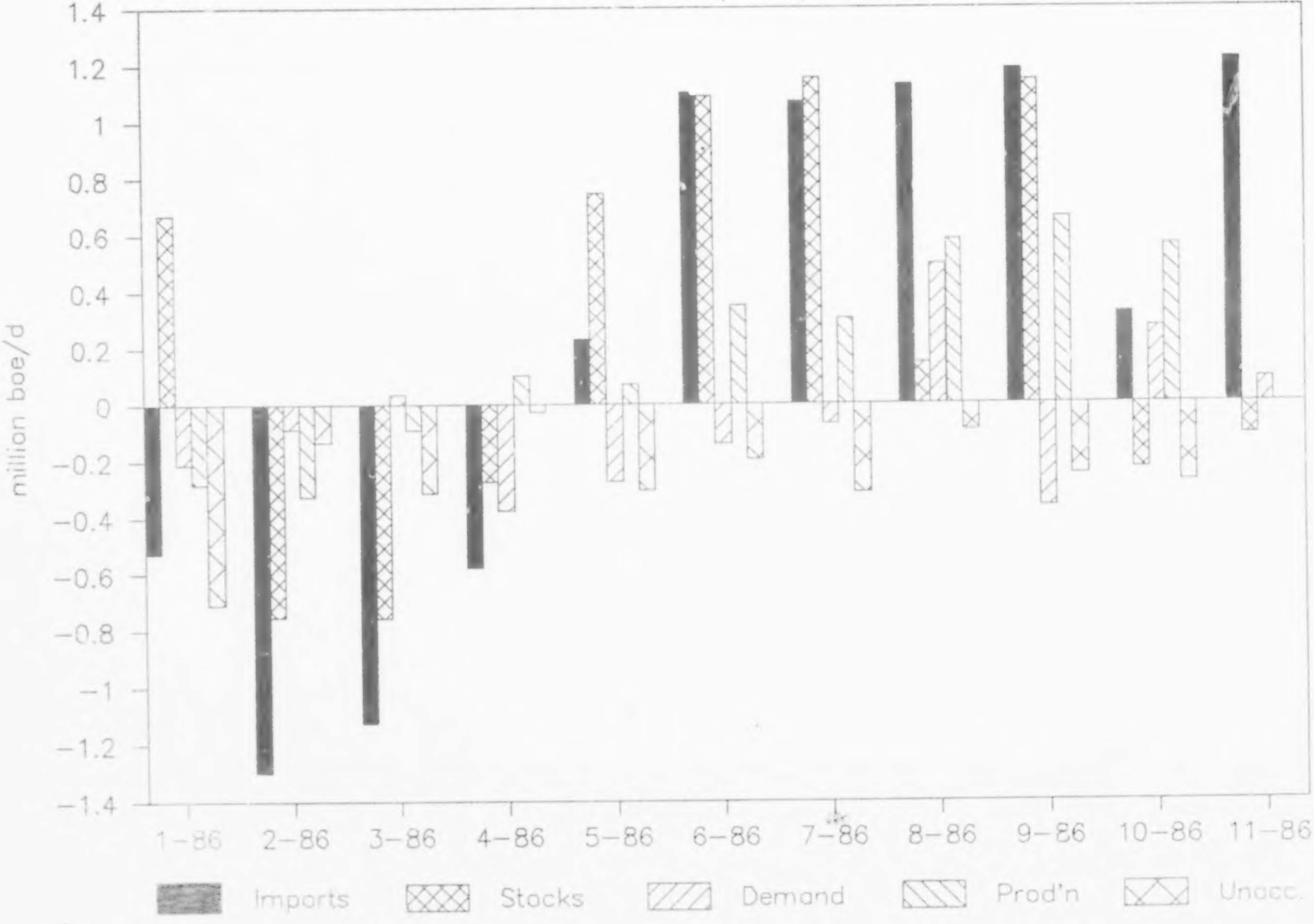
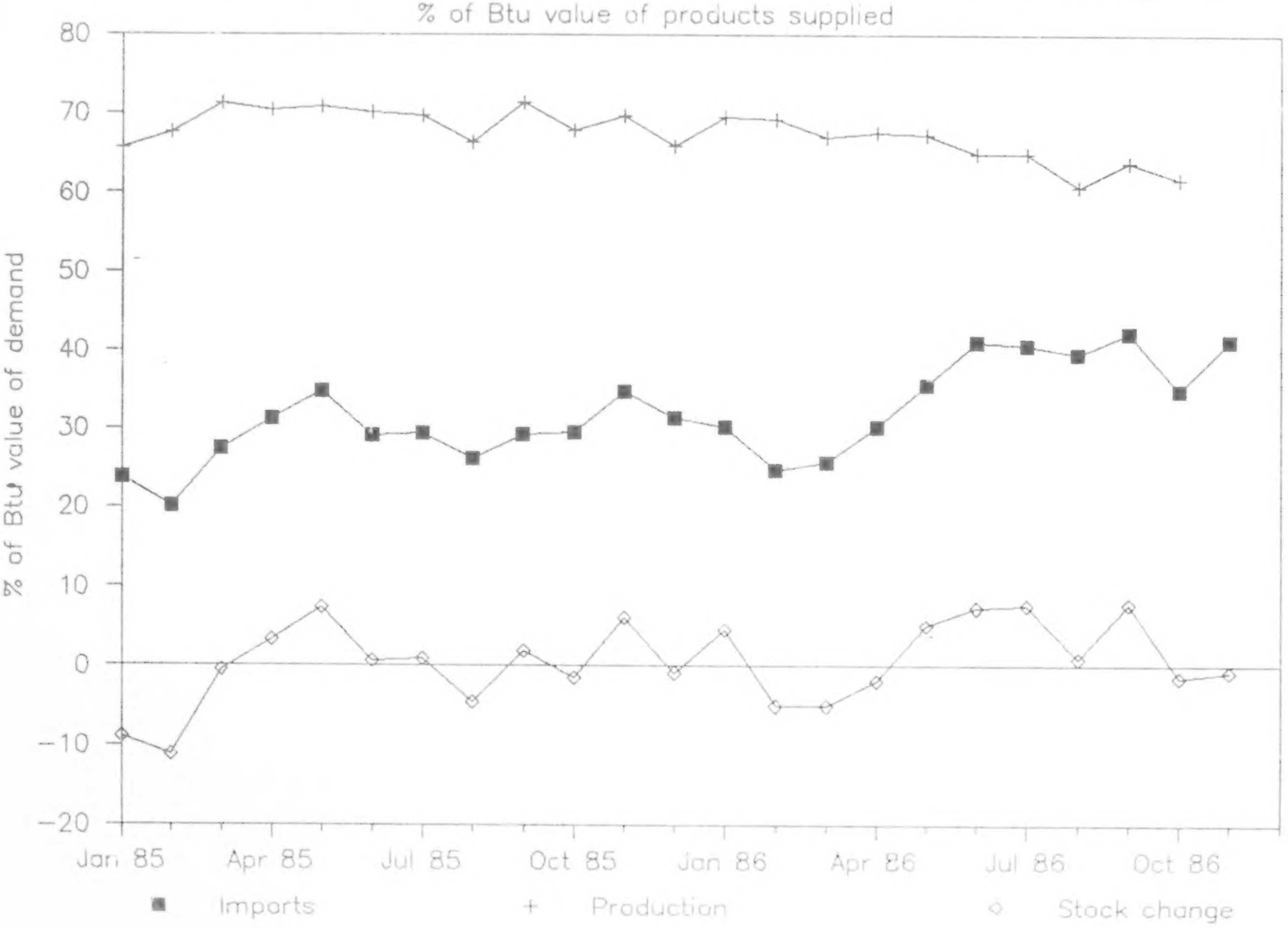


Exhibit C.9

U.S. petroleum production and imports



APPENDIX D

ANALYSIS OF INDUSTRY CASH FLOW REQUIREMENTS NEEDED TO SUSTAIN VARIOUS LEVELS OF EXPLORATION ACTIVITY

To develop a measure of the appropriate level of Federal support for exploration activity it is necessary to address the following questions:

- What is the socially desirable level of exploration, under different oil price scenarios?
- How much exploration activity will industry undertake in the absence of Federal incentives?
- What are the costs of different policies to make up the difference in exploration activity?

The information in this appendix contains a very preliminary analysis of the second and third questions. The analysis is based upon the assumption, used only for illustrative purposes, that the socially desirable level of exploration over the next few years is the level of activity achieved in 1984 -- well below the 1981 peak, yet higher than the 1986 level of activity. The analysis also uses a pessimistic oil price forecast -- an annual average refiner acquisition cost of $14 per barrel (in constant 1986 dollars) for the next four years. While this is not a "worst case" scenario, it is a plausible case in which the need for exploration incentives is relatively high.[1] The following questions are addressed:

- How much must the industry spend on exploration to bring exploration activity back to the 1984 level, assuming annual average oil prices stay at $14/bbl?
- If initiatives targeted on reserve creation are established, how much must the Federal government "spend"

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[1] In the first quarter of 1987 the average refiner acquistition cost of crude was well above $14 per barrel.

(via credits) to bring exploration activity back to the 1984 level, assuming oil prices stay at $14/bbl?

- How does this level of Federal expenditure compare with Federal oil and gas lease revenue?
- If incentives aimed at increasing the oil industry's cash flow are established, how much more must the Federal government "spend" relative to initiatives targeted on reserve creation?

These issues are examined below.

- **How much must the industry spend on exploration to bring exploration activity back to the 1984 level, assuming annual average oil prices stay at $14/bbl?**

To address this question we turn to the three major data sources on oil industry expenditures:

- the Joint Association Survey on Drilling Costs sponsored by the American Petroleum Institute, the Independent Petroleum Association of America, and the Mid-Continent Oil & Gas Association[2]
- the Annual Survey of Oil & Gas published by the Commerce Department
- the Financial Reporting System of the Energy Information Administration, based on Form EIA-28, with results published in Performance Profiles of Major Energy Producers.

We find that real expenditures appear to be linearly related to real oil prices, regardless which data series is used.[3]

To bring total exploration expenditures back to the 1984 level the industry would have to devote an additional $14 billion to exploration. To bring exploration drilling and geophysical work back to the 1984 level may require only $10 to $12 billion, however, because acreage should be cheaper in 1987 than in 1984.

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[2] This is the primary data source for the Energy Information Administration's report series on Indexes and Estimates of Domestic Well Drilling Costs.

[3] The linear relationship begins to break down when expenditures on acquisition of proved acreage (including corporate acquisitions) are included in the expenditure figures.

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ANALYSIS OF JOINT ASSOCIATION SURVEY DATA

Perhaps the most precise expenditure figures (through 1985) are the estimates of well drilling expenditures from the Joint Association Survey (JAS). Drilling expenditures include two components:

- the cost of drilling and equipping exploratory wells
- the cost of drilling and equipping development wells.

The industry uses these data to develop cost estimates for future wells. An estimate of 1986 drilling expenditures is available from the November Oil & Gas Journal.

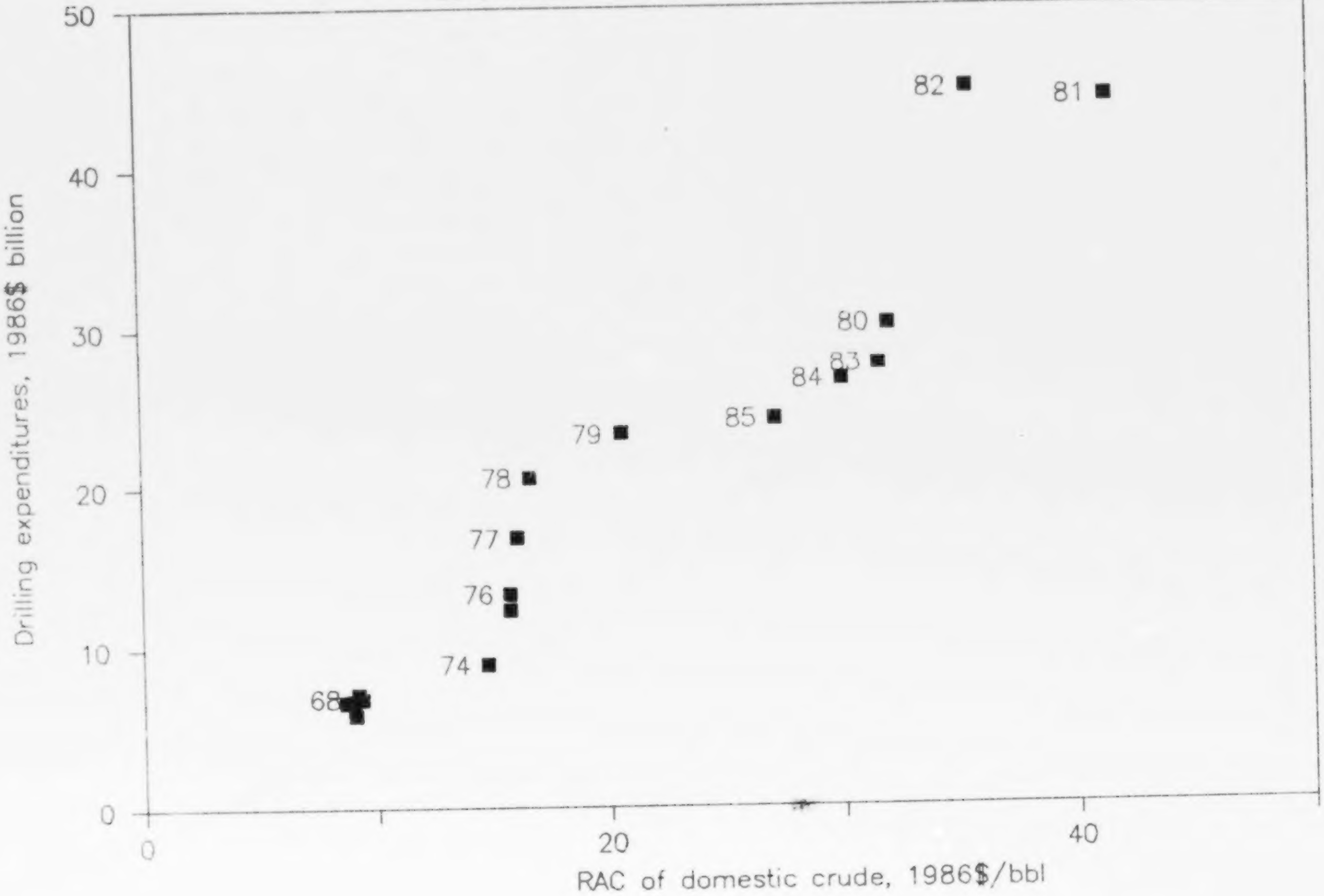
Total U.S. oil industry expenditures on drilling appear to be a linear (or nearly linear) function of the price of domestic crude oil (see Exhibit D.1).

These data suggest that the price drop of $16/bbl from 1984 to 1986 resulted in a drilling expenditure drop of $14 billion (in 1986 dollars).

Exhibit D.1

Well drilling expenditures, 1968–1985

as a function of domestic oil price



ANALYSIS OF DATA FROM THE ANNUAL SURVEY OF OIL & GAS

Exploration expenditures include four components:

- the cost of acquiring unproved acreage (e.g., bonuses paid for OCS leases in areas to be explored)
- the cost of geological and geophysical studies
- the cost of drilling and equipping exploratory wells
- other costs, including overhead and administration.

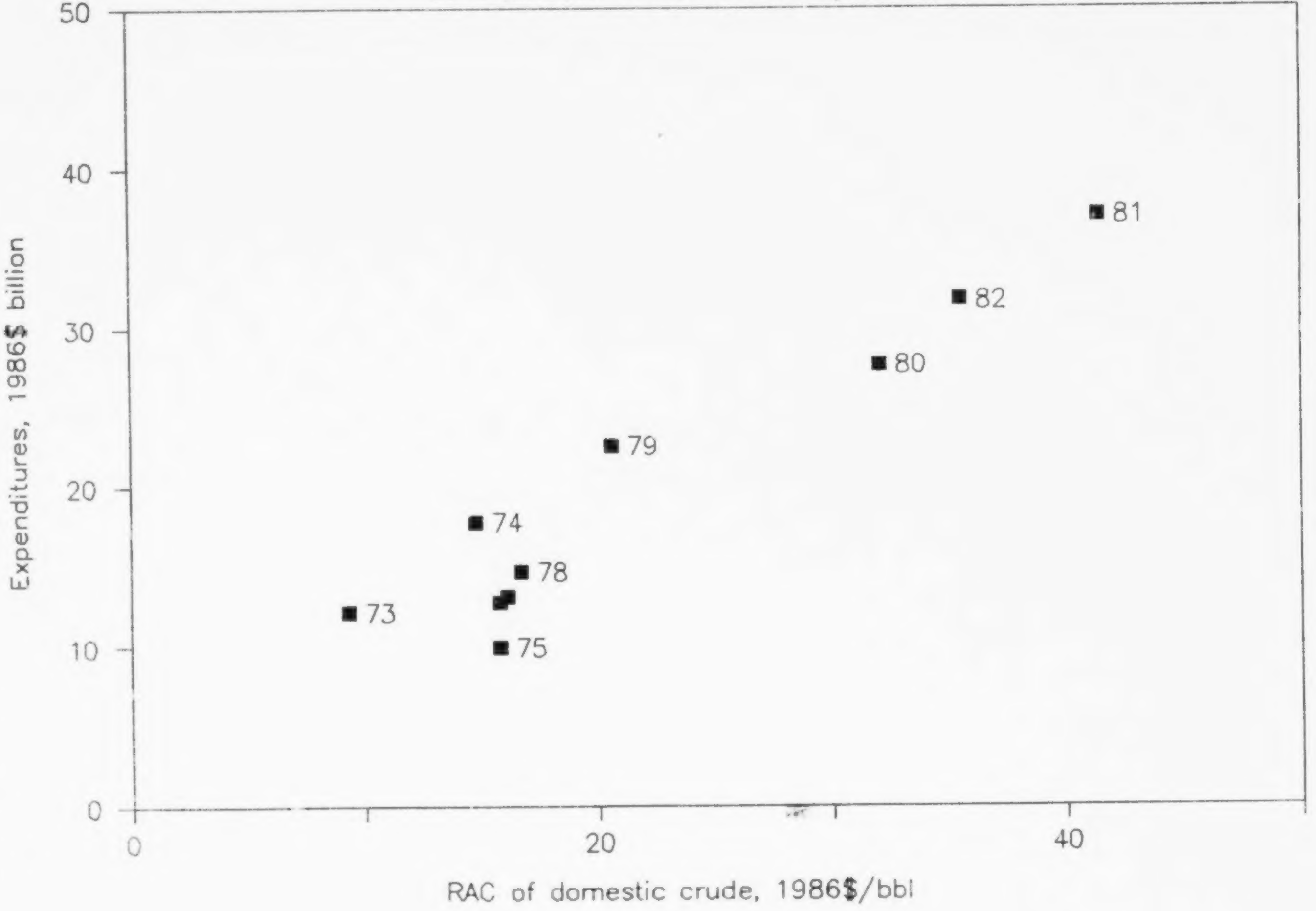
The Annual Survey of Oil & Gas published by the Commerce Department contains estimates of industry-wide domestic exploration expenditures.

Again, a linear relationship between expenditures and oil prices is apparent (see Exhibit D.2). These data suggest that the price drop of $16/bbl from 1984 to 1986 resulted in an exploration expenditure drop of $14 billion (in 1986 dollars).

Exhibit D.2

Industry exploration expenditures

as a function of domestic oil price



ANALYSIS OF FINANCIAL REPORTING SYSTEM DATA

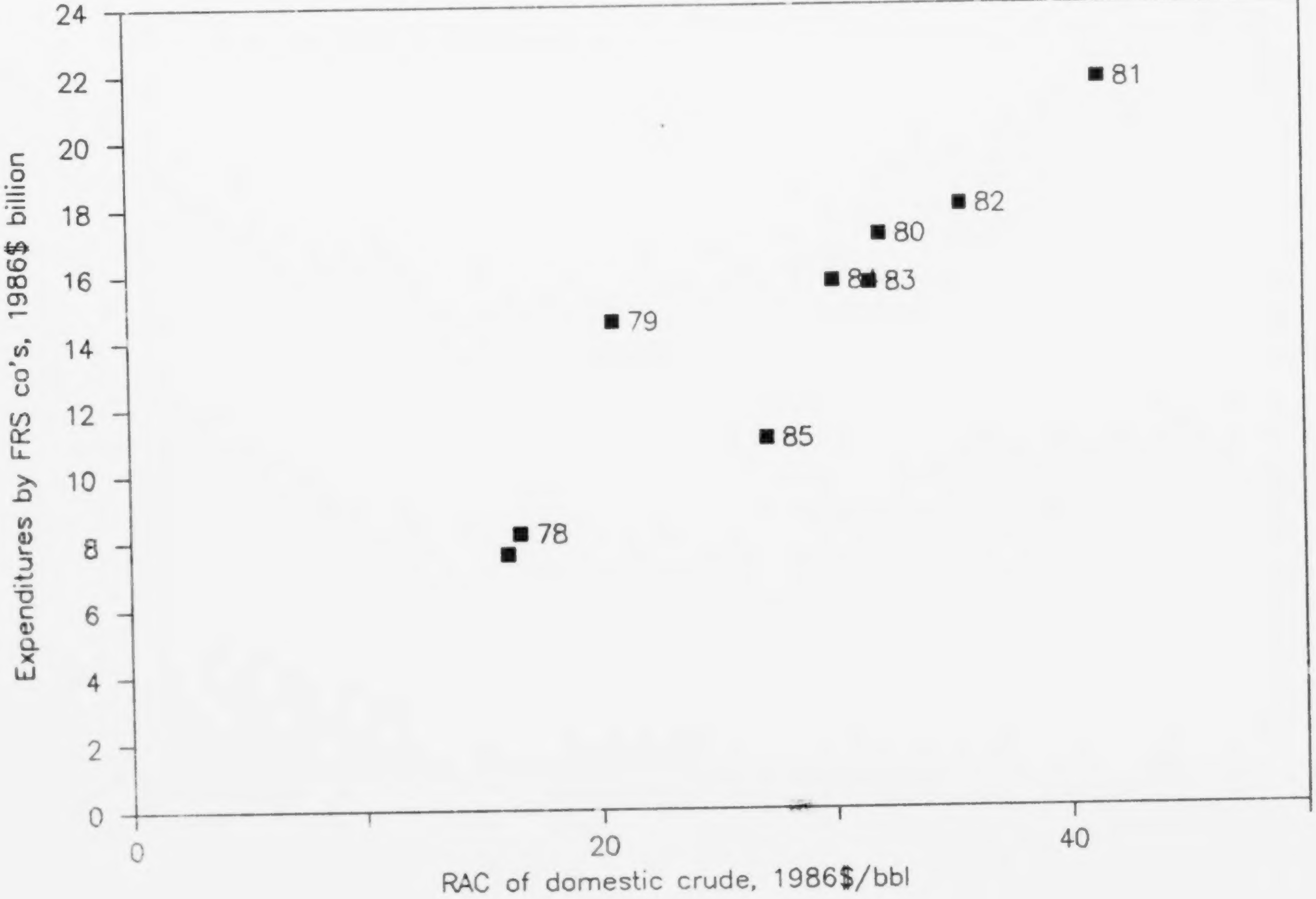
For the largest oil companies, data are available from the Financial Reporting System of the Energy Information Administration. For 1985 the EIA survey covered 26 companies, based on a 1976 sample, each of which held in 1976 at least 1 percent of U.S. oil production; oil reserves; refining capacity; petroleum product sales; gas production; gas reserves; or coal or uranium production or reserves.

Again, a linear relationship between expenditures and oil prices is apparent (see Exhibit D.3). The companies in the FRS group account for roughly 60 percent of domestic oil and gas exploration expenditures. These data support the hypothesis that the price drop of $16/bbl from 1984 to 1986 resulted in an industry-wide exploration expenditure drop of $14 billion (in 1986 dollars).

Exhibit D.3

Majors' expenditures on exploration

as a function of oil price



ADJUSTMENT FOR ACREAGE COSTS

In the past decade a large share of exploration expenditures has gone into acquisition of unproved acreage. For the industry and for the FRS group of companies, about 30 percent of exploration expenditure was devoted to acreage acquisition in 1976-1984 (see Exhibits D.4 and D.5).

Several factors affect the cost of acreage:

- As oil prices and price expectations decline, the cost of unproved acreage should decline.
- As Federal incentives for exploration (including acreage acquisition) increase, the cost of unproved acreage should increase. In particular, if exploration costs can be credited against Federal lease bonuses, expenditures on lease bonuses should increase.
- Assuming the better average is acquired earlier, prospect quality will decline over time.
- To the extent the Federal tract selection system limits acquisition,[4] bonus bids may be inflabed.

We hypothesize that the net effect of these factors will be a drop in costs of unproved acreage. The amount of exploration expenditure needed to restore exploratory drilling and geophysical activity to the 1984 level may therefore be only $10 to $12 billion.

If the effect of incentives targeted on exploration is to bid up bonus payments for Federal lands, the "cost" of incentives may appear to be larger than it really is. To minimize the amount of Federal "spending" targeted on exploration, it may be necessary to exclude Federal lease bonus payments from the definition of exploration expenditures qualifying for credits. To prevent a "windfall" to owners of unproved acreage, it may be necessary to exclude all acreage acquisition costs from the definition of exploration expenditures qualifying for credits.

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[4] For example, the 1976-1982 OCS program compared with area-wide leasing.

Exhibit D.4

Industry expenditures on exploration

Onshore and offshore U.S.

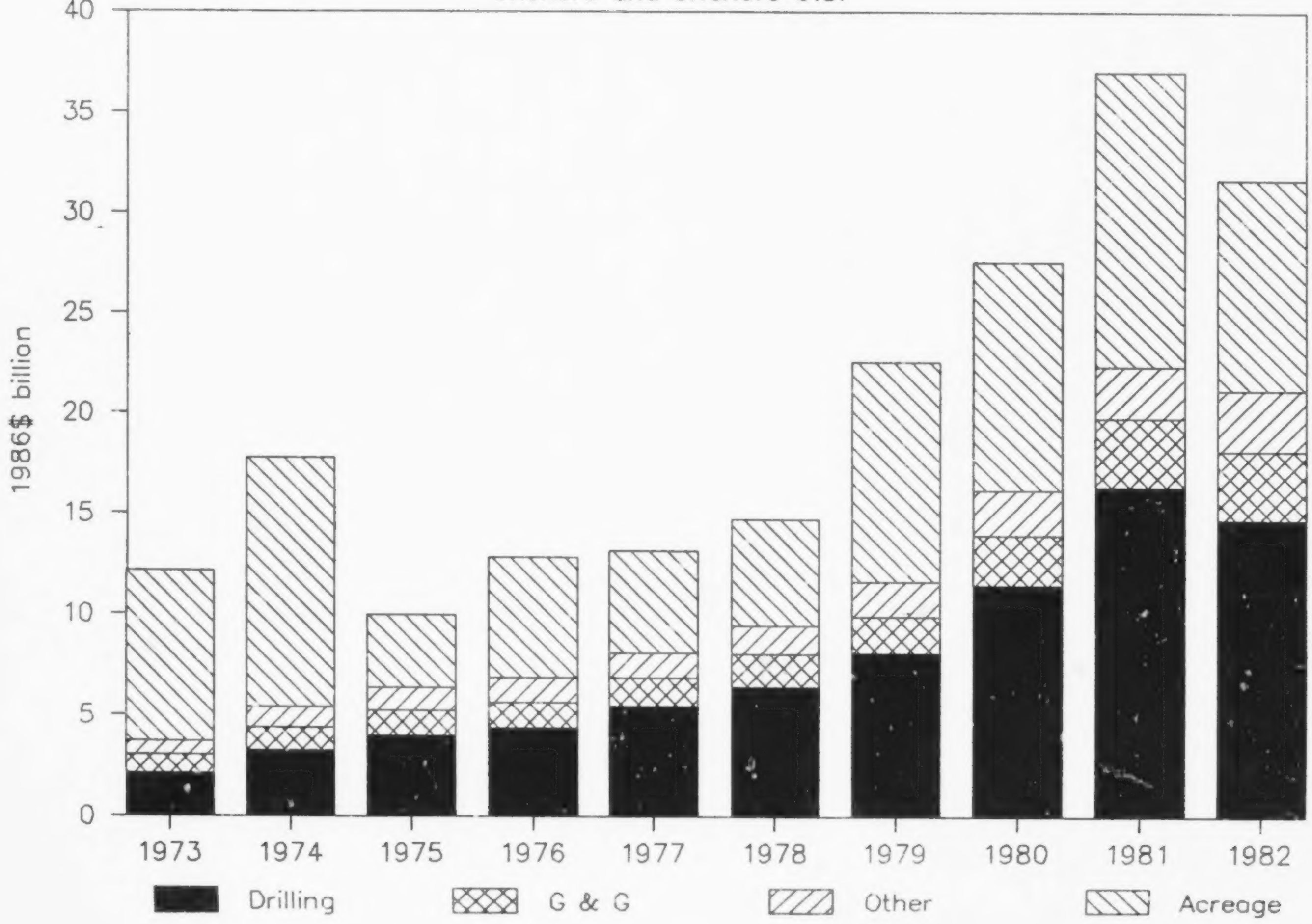
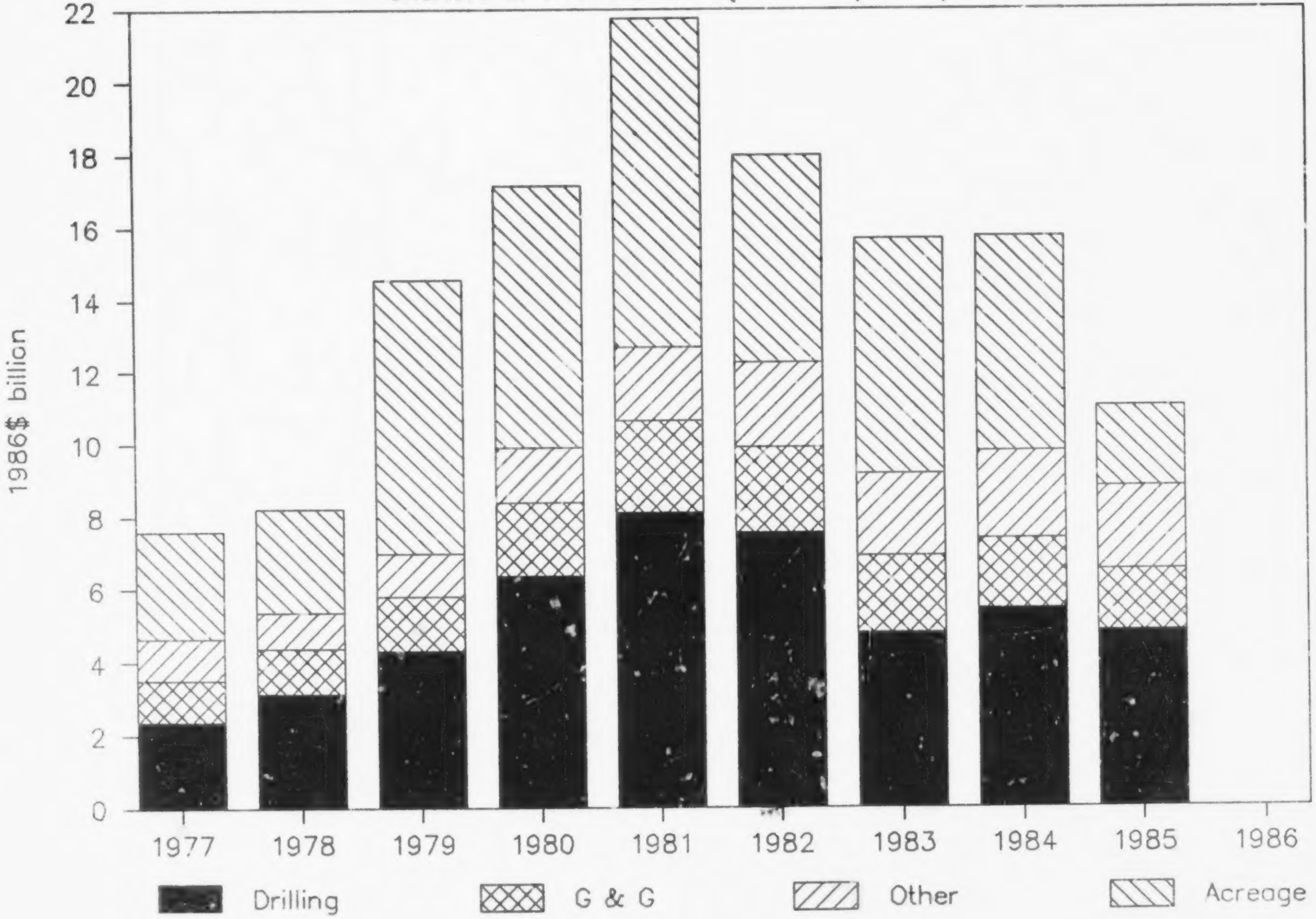


Exhibit D.5

Majors' expenditures on exploration

Onshore & offshore U.S. (FRS companies)



ADJUSTMENT FOR DRILLING COSTS

Over the past decade, drilling costs per foot and per well have risen and fallen with drilling activity. On this basis one would expect 1986 drilling costs to be lower than 1984 drilling costs. If it is possible to maintain drilling activity at the 1984 level and yet hold drilling costs at the 1986 level, the estimate of the incremental expenditure required to restore activity to the 1984 level must be adjusted downward. Conversely, if there has been a permanent loss of skilled manpower it will not be possible to restore drilling activity without incurring drilling costs above the 1984 level.

For the purposes of the present analysis we accept the hypothesis that when drilling activity returns to the 1984 level, inflation-adjusted drilling costs return to the 1984 level.

- **If initiatives targeted on reserve creation are established, how much must the Federal government "spend" (via credits) to bring exploration activity back to the 1984 level, assuming oil prices stay at $14/bbl?**

There are at least two alternative explanations for the correlation between real exploration expenditures and real oil prices:

> **The imperfect capital market hypothesis:** Oil and gas exploration is a risky venture for which the only significant source of capital is cash flow from oil company operations. As oil prices rise, funds from operations rise. If a rise in oil prices does not occur, every additional dollar of exploration spending must be raised through new taxes, import fees, reductions in Federal lease revenue, or reductions in Federal tax receipts.
>
> **The efficient capital market hypothesis:** Investment in oil and gas exploration is driven by the expected after-tax net present values of exploration prospects, which in turn are driven by the price of oil. If ATNPV is raised by some factor other than the price of oil (e.g., Federal incentives), capital markets will provide capital for oil exploration from sources other than oil company funds from operations.

From the Federal standpoint, the imperfect capital market hypothesis is the worst case. It suggests that the government must "spend" $10 to $12 billion in exploration credits (or much more in unrestricted cash flow enhancement) to raise drilling activity to the 1984 level.

If the efficient capital market hypothesis is accepted and acreage acquisition costs do not qualify for exploration credits, the percentage credit against exploration expenditure equals the percentage needed to raise ATNPV of an exploration prospect to the ATNPV level associated with $30 oil (or some particular oil price "target"). If this percentage is 10 percent, for example, only $1 billion of exploration credit is required to raise drilling to the 1984 level.

- **How does this level of Federal expenditure compare with Federal oil and gas lease revenue?**

Federal oil and gas lease revenues will fall as oil prices fall. Because crude oil prices dropped in the middle of FY86, FY87 lease revenues may be lower than FY86 lease revenues. Total FY86 lease revenue was $4.086 billion ($3.615 billion in royalties, $0.131 billion in rents, and $0.34 billion in bonuses). Because oil royalty revenues decline in proportion to crude oil prices, FY87 lease revenue may be on the order of $3 billion only 25 to 30 percent of the $10 to 12 billion of exploration expenditure required to bring expenditures back to the 1984 level.

If the efficient capital market hypothesis is accepted and acreage acquisition costs do not qualify for exploration credits, the dollar amount of Federal lease revenue may be large enough to provide a source of exploration credits that will return exploration activity to 1984 levels.

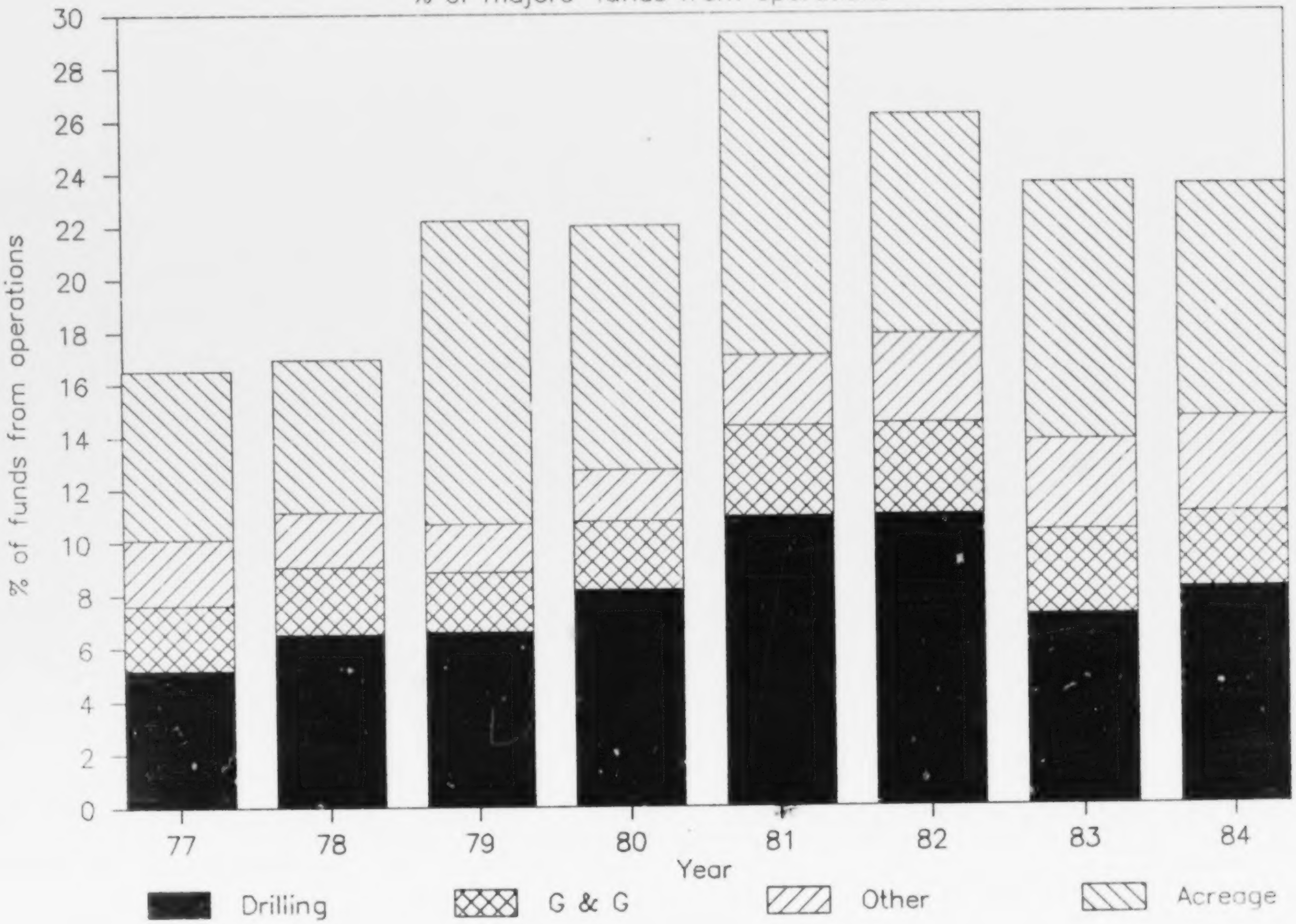
- **If incentives aimed at increasing the oil industry's cash flow are established, how much more must the Federal government "spend" relative to initiatives targeted on reserve creation?**

Over the last decade the level of the FRS companies' exploration spending, expressed as a percentage of funds from operations, has varied with the price of oil. In 1977-1978 the real price of domestic crude was roughly comparable to today's price, and the FRS companies allocated about one sixth of their cash flow to exploration (see Exhibit D.6). These data suggest that when incentives aimed at increasing the oil industry's cash flow are established, the Federal

Exhibit D.6

Cash flow devoted to exploration

% of majors' funds from operations



government must "spend" six times more to achieve the level of exploration activity associated with a particular amount of exploration credits. This sixfold increase in spending may be considered prohibitive.

- **What is the relationship between projected oil prices and projected domestic exploration expenditure?**

In May 1986 the American Petroleum Institute published the results of a survey designed to measure the sensitivity of future exploration activity to prices and price expectations. Survey respondents were asked to project capital and operating expenditures for exploration and production, and project the number of wells drilled, under each of four "flat" price scenarios for 1986-1991: $10, $15, $20, and $30 per barrel.[5] The survey results show a linear relationship between the 1986-1991 oil price level and E&P expenditures, and a linear relationship between the 1986-1991 oil price level and the number of wells drilled (see Exhibit D.7).

Under a low oil price projection, the growth of annual imports is driven by more rapid growth of demand as well as a drop in domestic production. The National Petroleum Council, among other organizations, has developed long-term projections of total petroleum product demand and imports.[6] Under a "high" price projection ($36 per barrel in the year 2000) the share of domestic demand met by imports grows substantially (see Exhibit D.8).

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[5] American Petroleum Institute, Results of the API Crude Oil Price Effects Survey, May 1986, cited in American Petroleum Institute, Domestic Petroleum Production and National Security (Washington, D.C.: API, December 30, 1986), p. II-6.

[6] National Petroleum Council, U.S. Oil and Gas Outlook: An Interim Report of the National Petroleum Council, October 1986, cited in American Petroleum Institute, Domestic Petroleum Production and National Security, pp. II-4, II-8, II-10.

Exhibit D.7

Exploration expenditures in 1991

at various crude oil prices

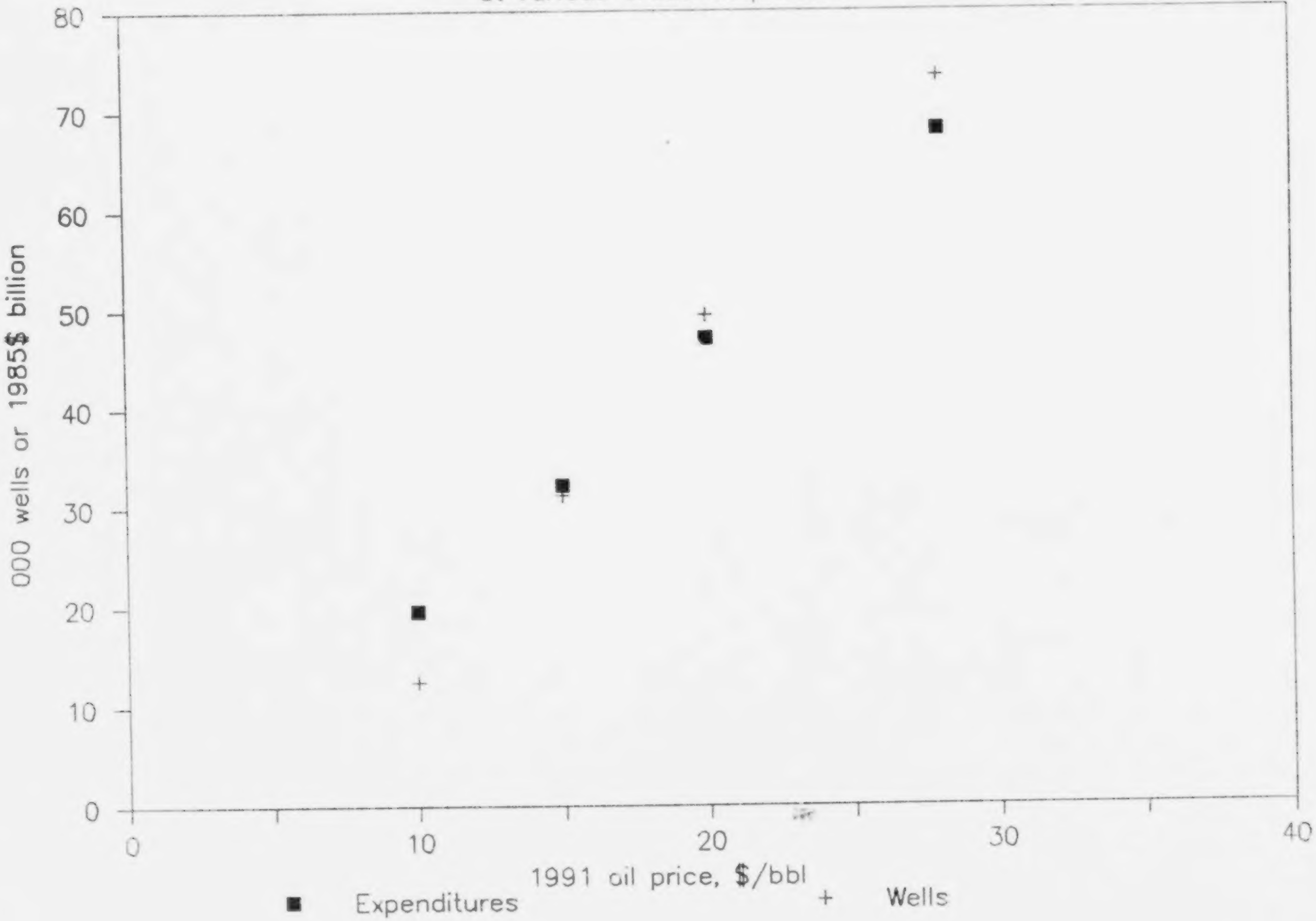
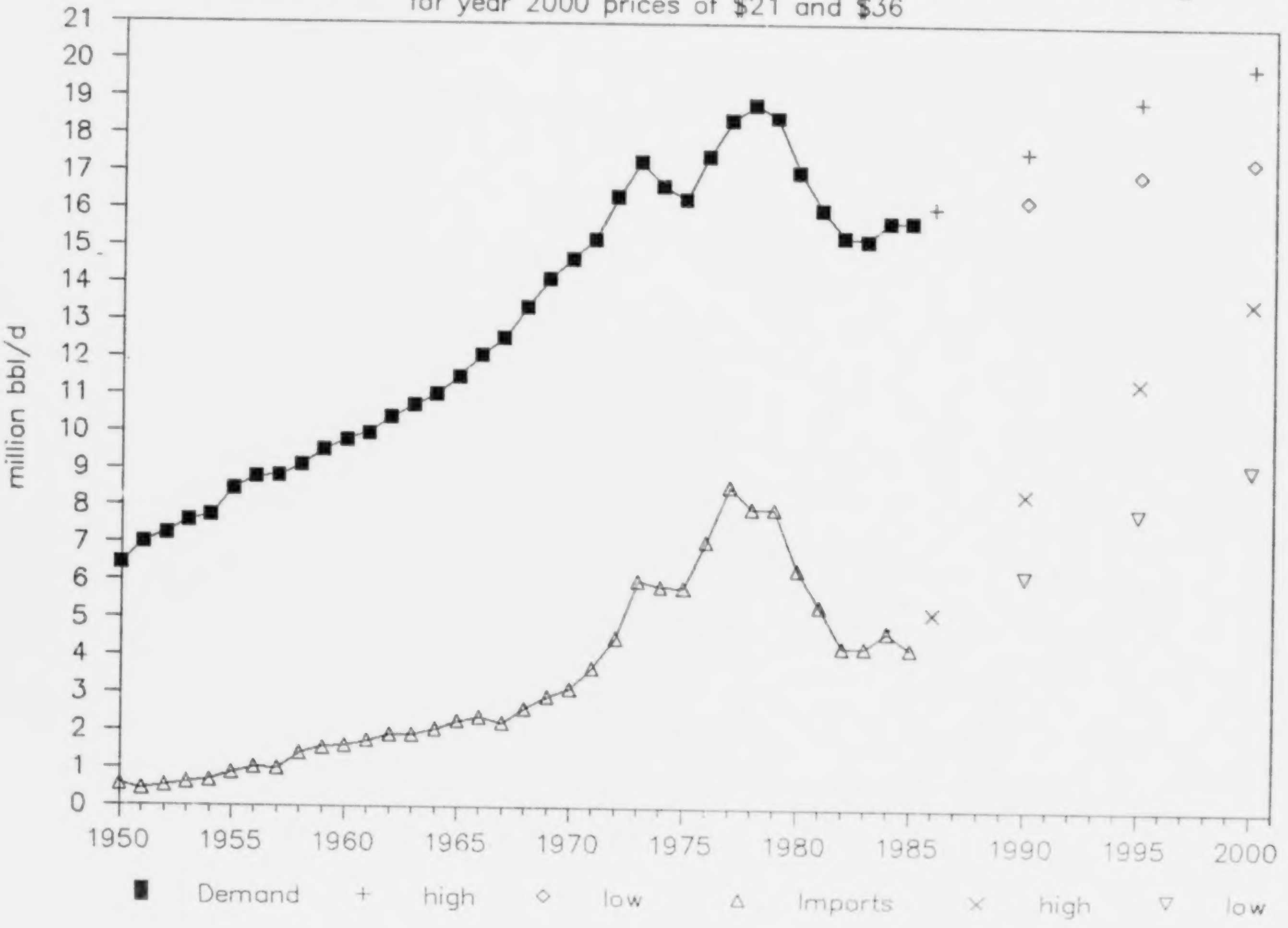


Exhibit D.8

Projected petroleum demand and imports

for year 2000 prices of $21 and $36



APPENDIX E

ANALYSIS OF THE EFFECT OF INCREMENTAL EXPLORATION ACTIVITY ON DOMESTIC RESERVE ADDITIONS

One of the criteria by which a program to support frontier exploration might be judged is the "simple" cost-effectiveness of the program -- the incremental reserve additions[1] obtained per dollar of Federal support for exploration. Although this is not a complete measure of cost-effectiveness because it fails to capture improvements in the nation's ability to increase domestic production in response to a sharp oil price increase, it is perhaps the simplest measure to understand.

To project the simple cost-effectiveness of proposed programs designed to promote high risk exploration in frontier areas it is necessary to:

- project the incremental exploration activity attributable to projected Federal support for exploration
- project incremental reserve additions associated with incremental exploration activity.

This appendix presents a preliminary analysis focused upon the second issue.

If reserve additions per unit of exploration effort (e.g., per dollar of exploration expenditure, adjusted for inflation) are expected to decline over the next decade, the cost-effectiveness of a Federal program to support exploration may decline. In the worst case, Federal support for frontier exploration would be only a "quick fix" because exploration prospects would rapidly be exhausted.

In this appendix recent trends in reserve/production ratios and drilling success ratios are examined to determine whether the level of exploration activity required to maintain a certain level of annual oil reserve additions will increase over the next decade. The tentative conclusion is that the benefits of frontier exploration activity will decline only slightly, if at all, over a time period as short as a decade. Because oil price fluctuations could cause large year-to-year fluctuations in U.S. reserve revisions and adjustments, however, over the next decade it will probably be difficult to discern trends in reserve additions per unit of exploration activity.

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[1] More precisely, the increment of reserve addition that is moved forward in time, and by how much.

RECENT TRENDS IN THE U.S. RESERVE/PRODUCTION RATIO

Over the past decade domestic crude oil production has been nearly constant. Reserve additions have been well below consumption but occasionally above production (see Exhibit E.1). On average, reserve additions have been below production and the reserve/production ratio has therefore fallen.

If production is constant, a policy target could be defined in terms of the ratio of reserve additions to production. From the standpoint of national energy security it makes more sense, however, to define a target in terms of either a reserve/production ratio or a reserve/consumption ratio.[2] Achievement of the reserve/production ratio of the 1970s may be an unrealistic policy goal, however, because the fields remaining to be discovered today may be smaller and higher-cost than the fields discovered in the 1970s.

Over the last decade the U.S. oil reserve/production ratio has fallen from about 11 years in 1977 to about 8.6 years in 1985 (see Exhibit E.2). If this ratio continues to fall, the U.S. will be increasingly vulnerable to manipulation of world oil markets.

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[2] A Strategic Petroleum Reserve target is best defined in terms of a reserve/consumption ratio (e.g., two "average" months of consumption).

Exhibit E.1

Crude reserve additions and production

and petroleum product demand

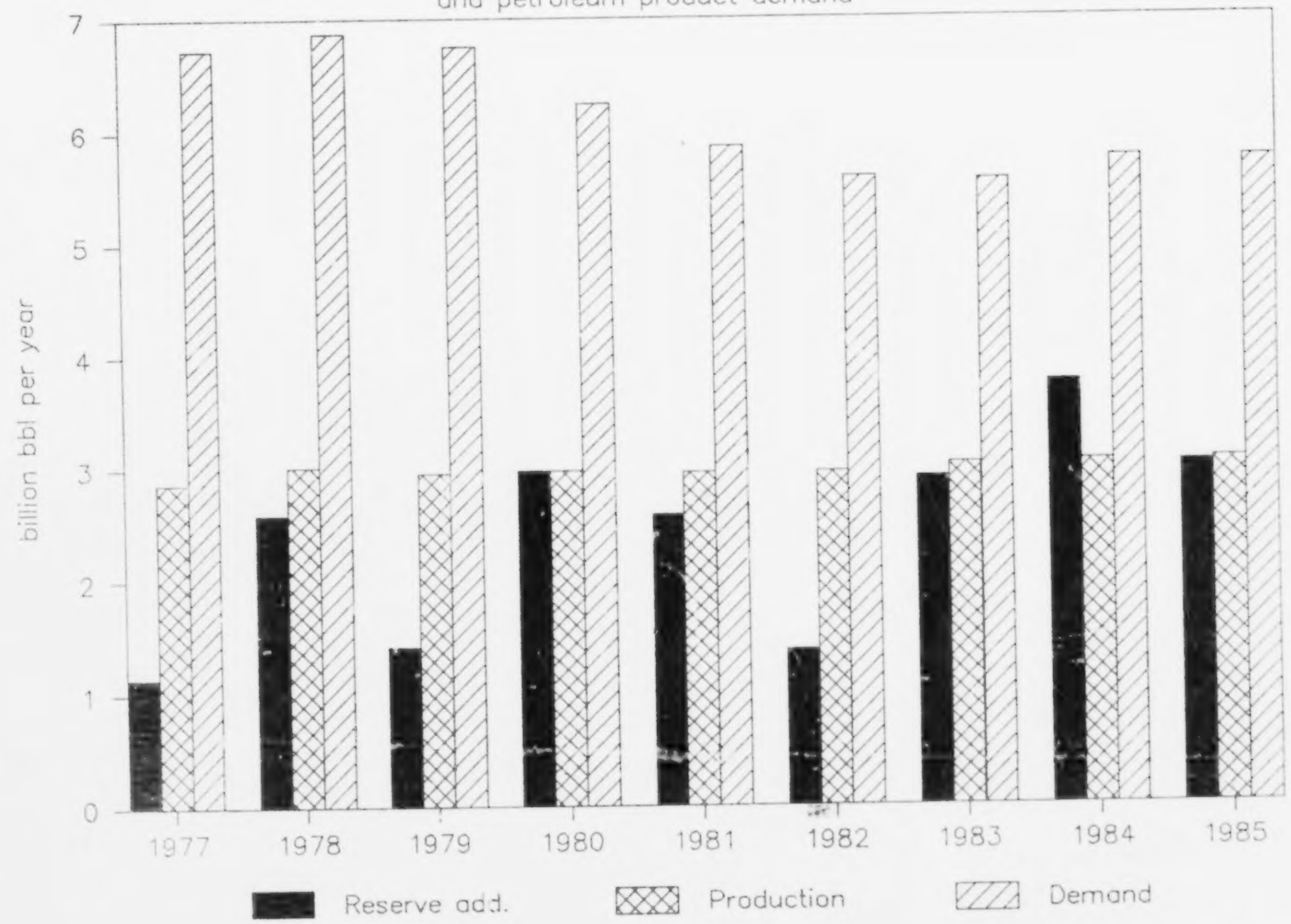
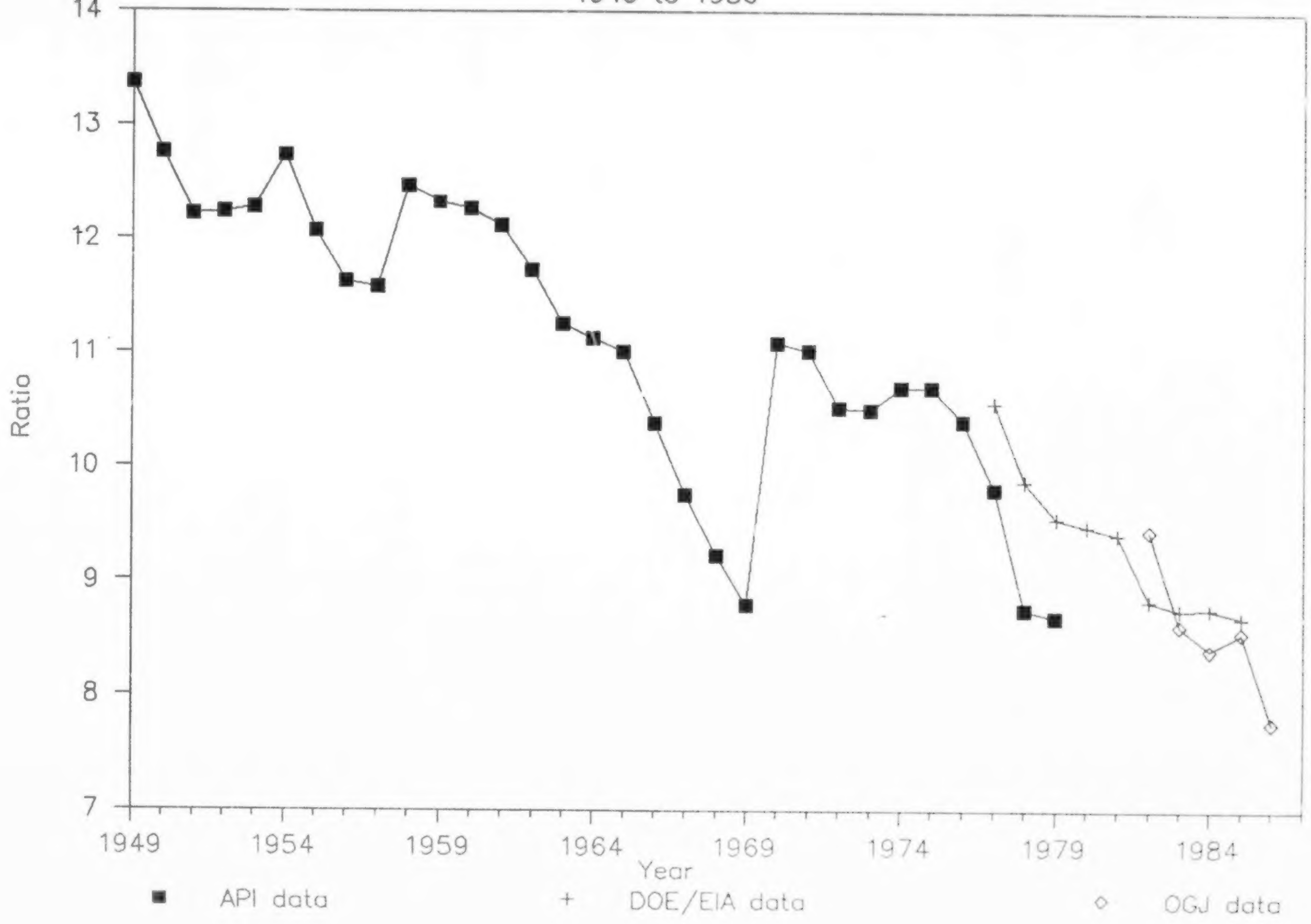


Exhibit E.2

U.S. oil reserve/production ratio

1949 to 1986



RESERVE/PRODUCTION RATIOS OF OTHER COUNTRIES

Among the countries with over 5 billion barrels of oil reserves at January 1, 1987, it appears that the U.S. in 1986 had the lowest reserve/production ratio (see Exhibit E.3). On the basis of a preliminary estimate of January 1, 1987 reserves published by the Oil & Gas Journal, it appears that the U.S. reserve/production ratio was 7.7 in 1986. The ratio of proved reserves to production is not available for the U.S.S.R.; the Soviet reserve/production ratio was 13.1, if "probable reserves" and some "possible reserves" are included.[3]

Among non-Communist countries outside the Mideast, Mexico and Venezuela have substantial oil reserves (see Exhibit E.4). In the long run U.S. oil supply security may depend heavily on imports from these two countries.

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[3] These data were obtained from the Oil & Gas Journal, December 22/29, 1986, pp. 33-40.

Exhibit E.3

Reserve/ production ratios

1-1-87 reserves and 1986 production

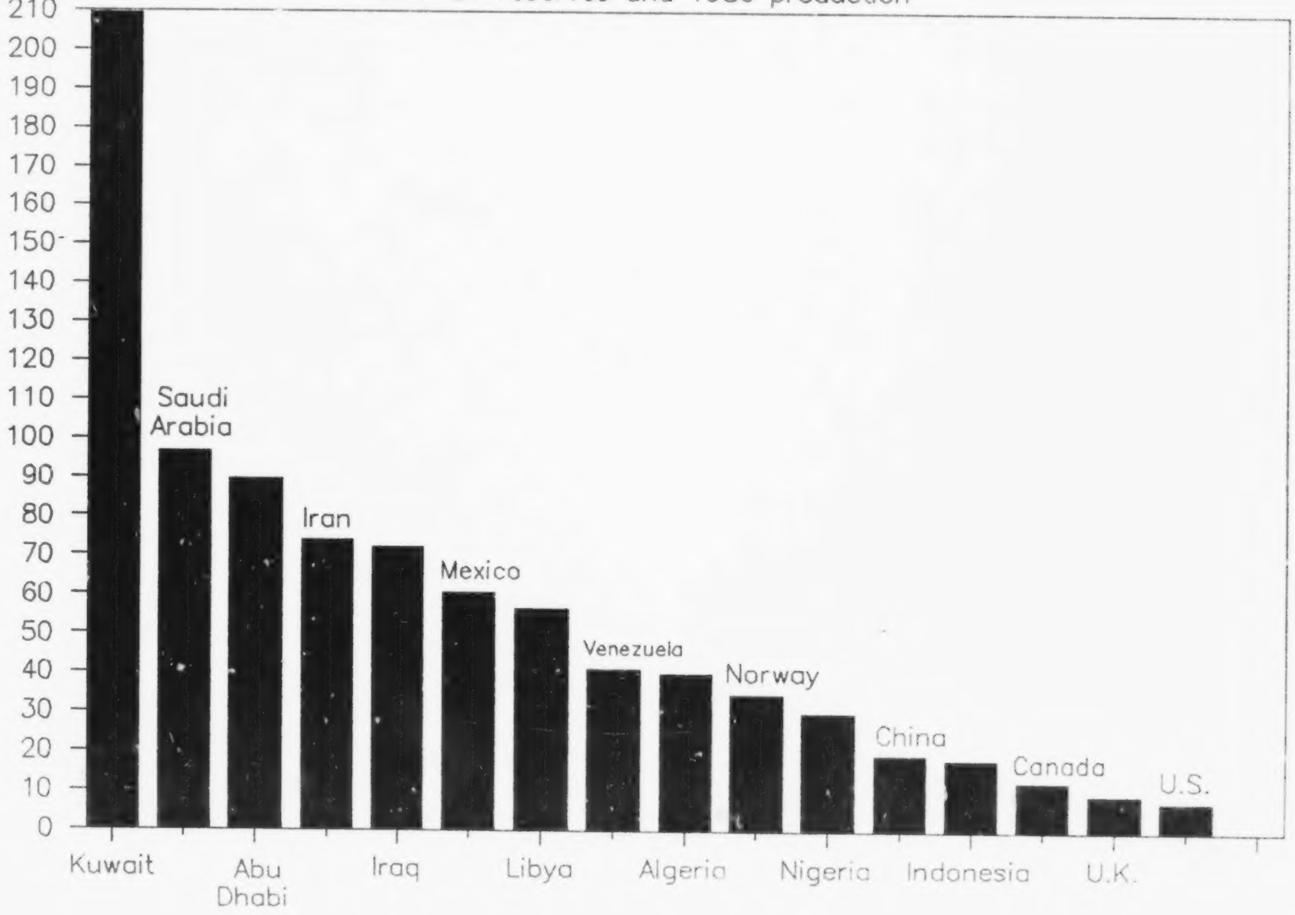
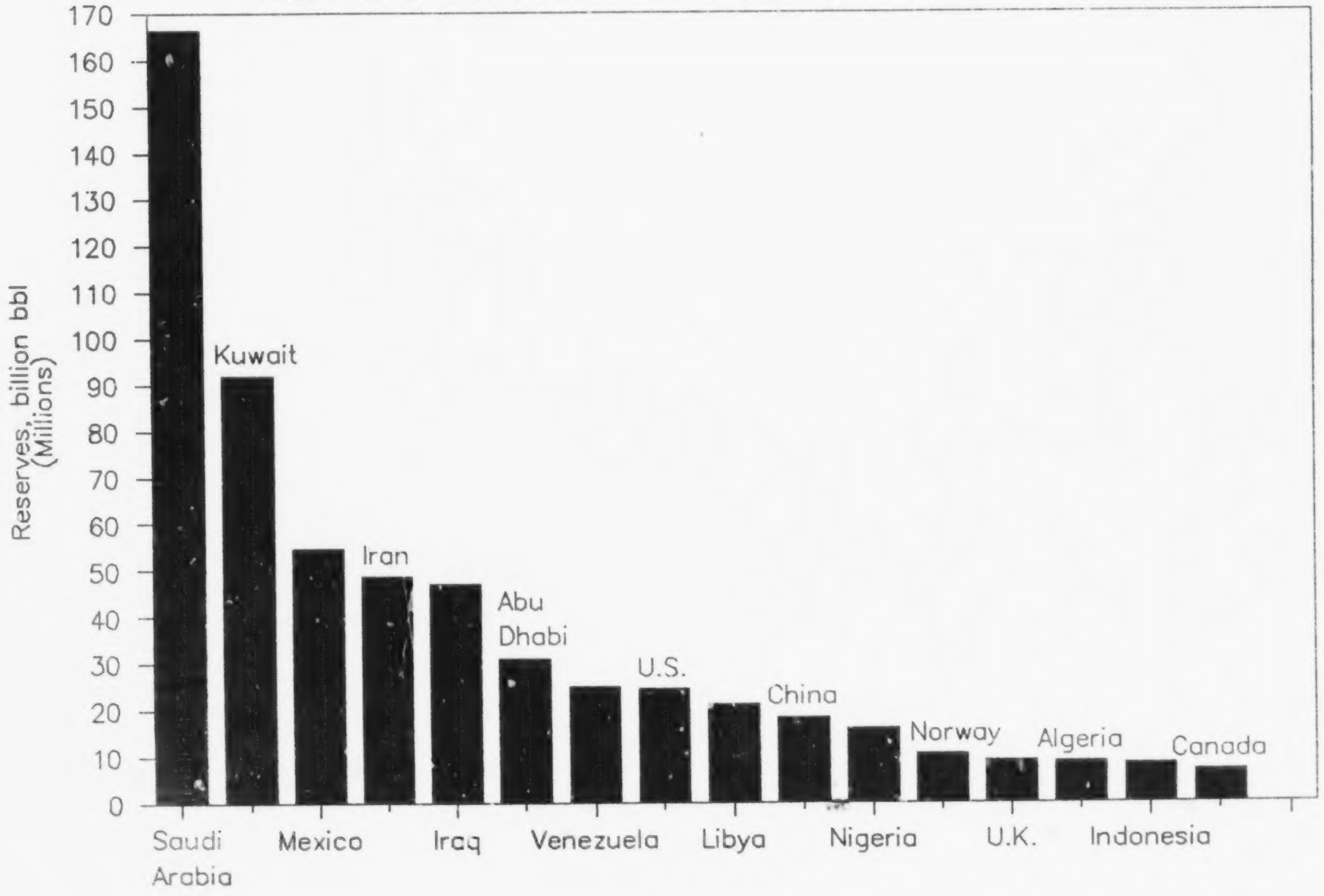


Exhibit E.4

Crude oil reserves at Jan. 1, 1987



TRENDS IN RESERVE ADDITIONS PER UNIT OF EXPLORATION ACTIVITY

Two factors affect the level of reserve additions per unit of exploration activity:

- The tendency for domestic resources to approach exhaustion, over time; the tendency for exploration to move to increasingly hostile environments and complex geologic structures

- The tendency for new technology to improve exploration techniques and lower the cost of finding oil in any given environment or geological structure.

If the second factor were not present, we would certainly expect to see diminishing returns diminishing reserve additions per unit of exploration effort.

Proven resources may be defined as the sum of measured and indicated reserves; unproven resources may be defined as the sum of inferred and undiscovered resources. The relative size of these resources in 1979 is illustrated in Exhibit E.5. If the latest Geological Survey (1981) mean estimates of onshore undiscovered resources and Minerals Management Service (1984) mean estimates of offshore undiscovered resources are used in combination with annual Energy Information Administration estimates of annual reserves and production, the trend toward resource exhaustion can be illustrated graphically (see Exhibit E.6). The original recoverable domestic oil in place in the United States appears to be about 240 billion barrels. The undiscovered portion has shrunk significantly over the last decade.

Nonrecoverable resources are not included in the 240 billion barrel figure. In the long run, oil resources that are economically nonrecoverable today may someday become economically recoverable. The cost of non-petroleum energy sources and energy efficiency gains (e.g., through conservation) may be low enough, however, that our nation's most expensive liquid hydrocarbon resources may never be extracted.

Exhibit E.5

U.S. oil resources remaining in 1979

USGS (1981) and MMS (1984) estimates

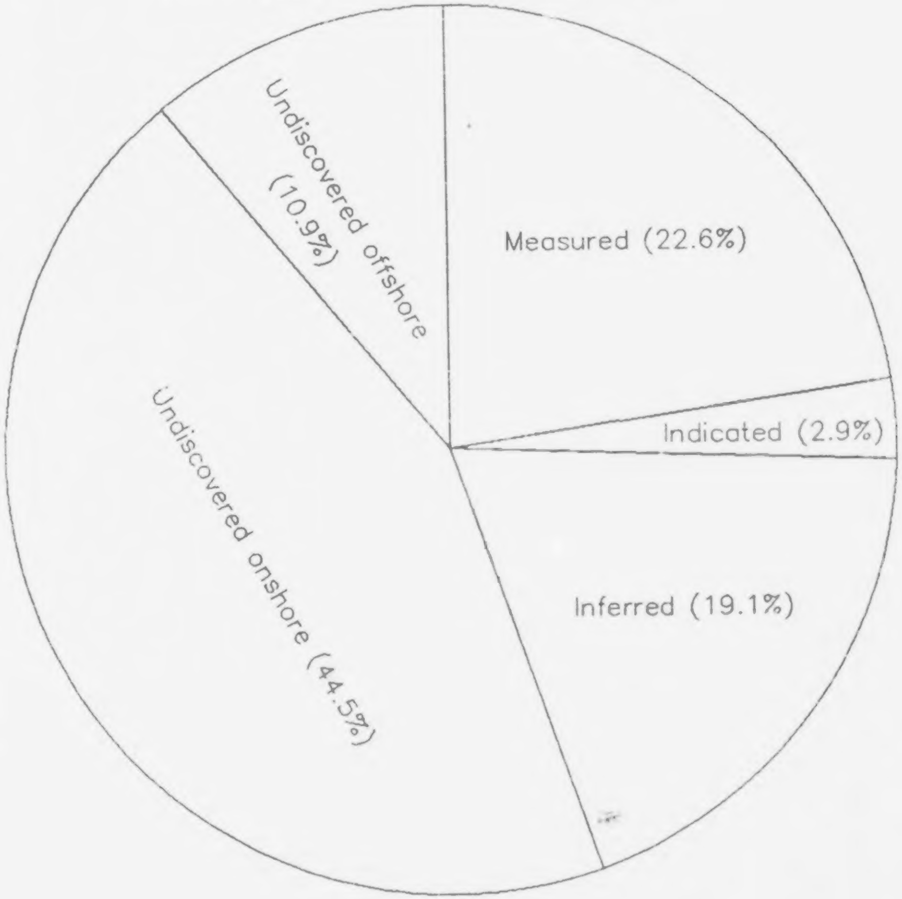
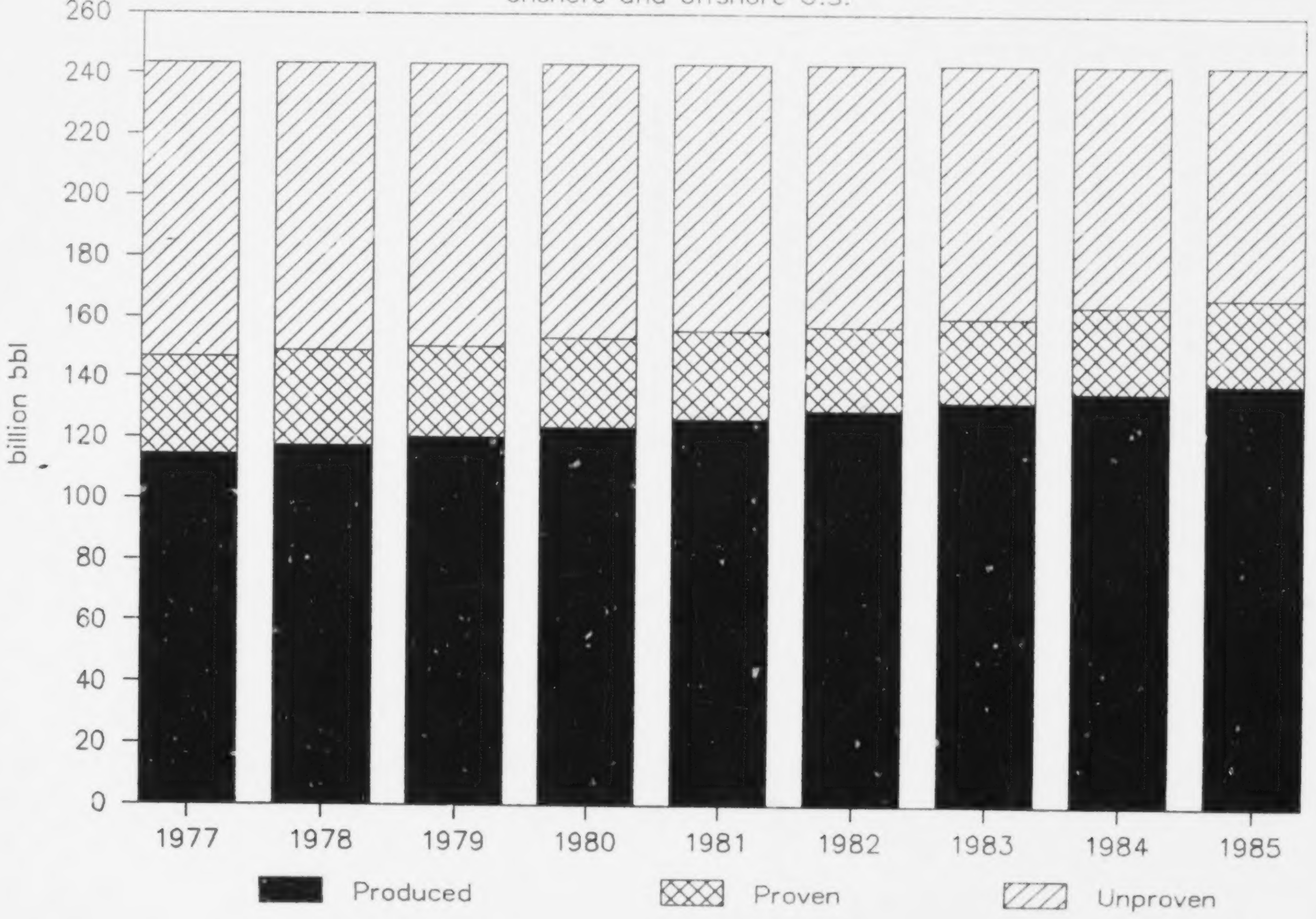


Exhibit E.6

Composition of recoverable oil in place

onshore and offshore U.S.



THE DIFFICULTY OF LINKING RESERVE ADDITIONS TO A PARTICULAR YEAR'S EXPLORATION ACTIVITY

The tendency for exploration activity to yield diminishing (or increasing) returns is difficult to measure because it is difficult to attribute reserve additions to a particular year's exploration activity. Two problems arise:

1. It is difficult to allocate exploration costs (other than the cost of successful wells) between oil reserve additions and natural gas (and NGL) reserve additions.
2. When an oil reserve is first discovered, the amount of the reserve (the economically recoverable oil) is not immediately known. Revisions and adjustments to the reserve estimate may be booked many years later.

Reserve additions have two principal components:

- Discoveries including extensions to old reservoirs, new field discoveries, and new reservoir discoveries in old fields
- Revisions and adjustments - including revisions based on reservoir performance data and economic factors affecting recovery, and adjustments for sampling and reporting errors.

Discoveries may be attributed to recent exploration activity, but revisions and adjustments have no logical connection with current exploration activity. Over the last decade, the primary source of U.S. reserve additions has been revisions and adjustments (see Exhibit E.7). A portion of these revisions and adjustments are associated with development drilling. As oil prices rose in the 1970s, development drilling took an increasing share of total drilling (see Exhibit E.8).

Perhaps the most thorough recent study of domestic finding rates is the study completed by the Gas Research Institute in

Exhibit E.7

Components of oil reserve additions

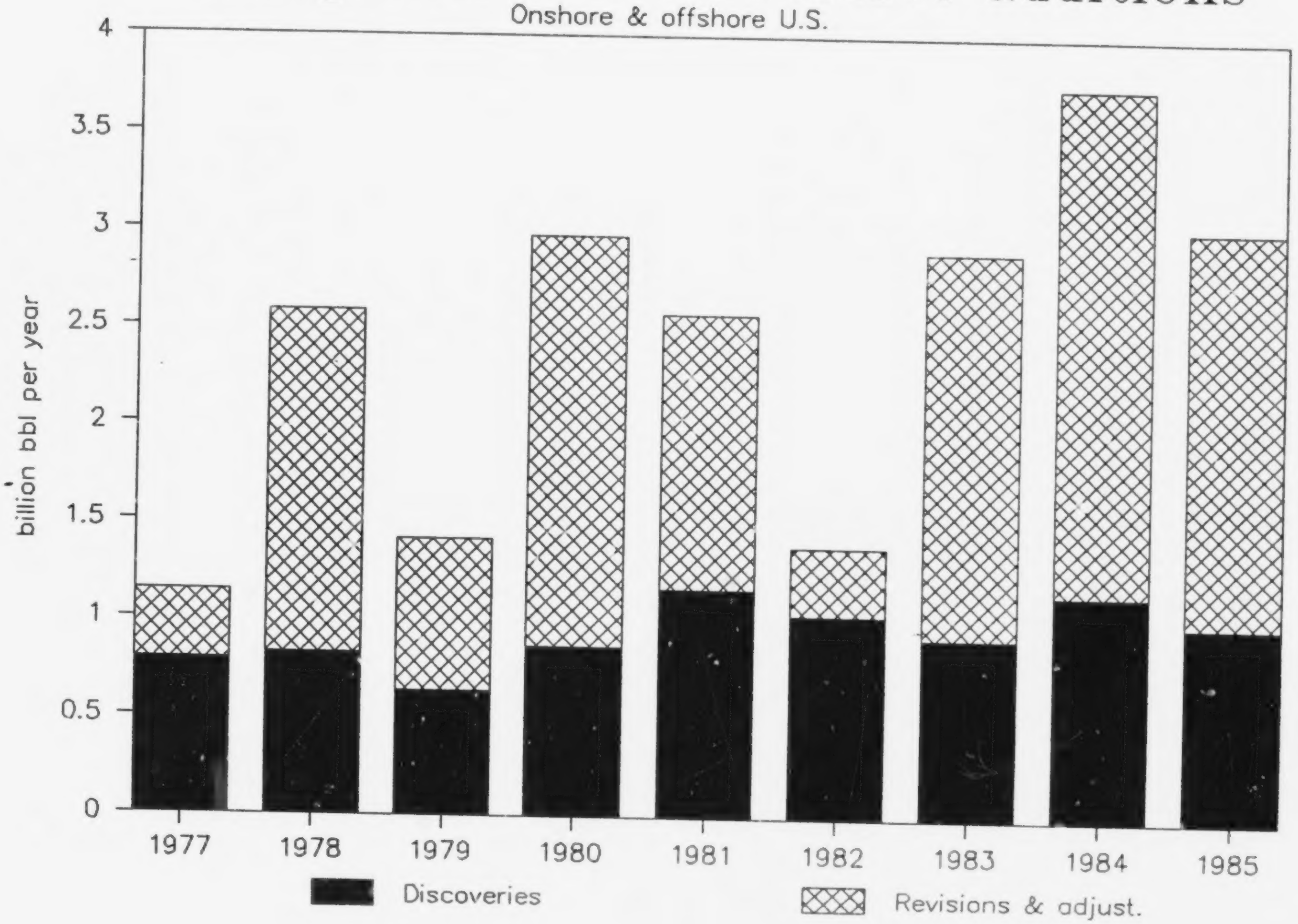
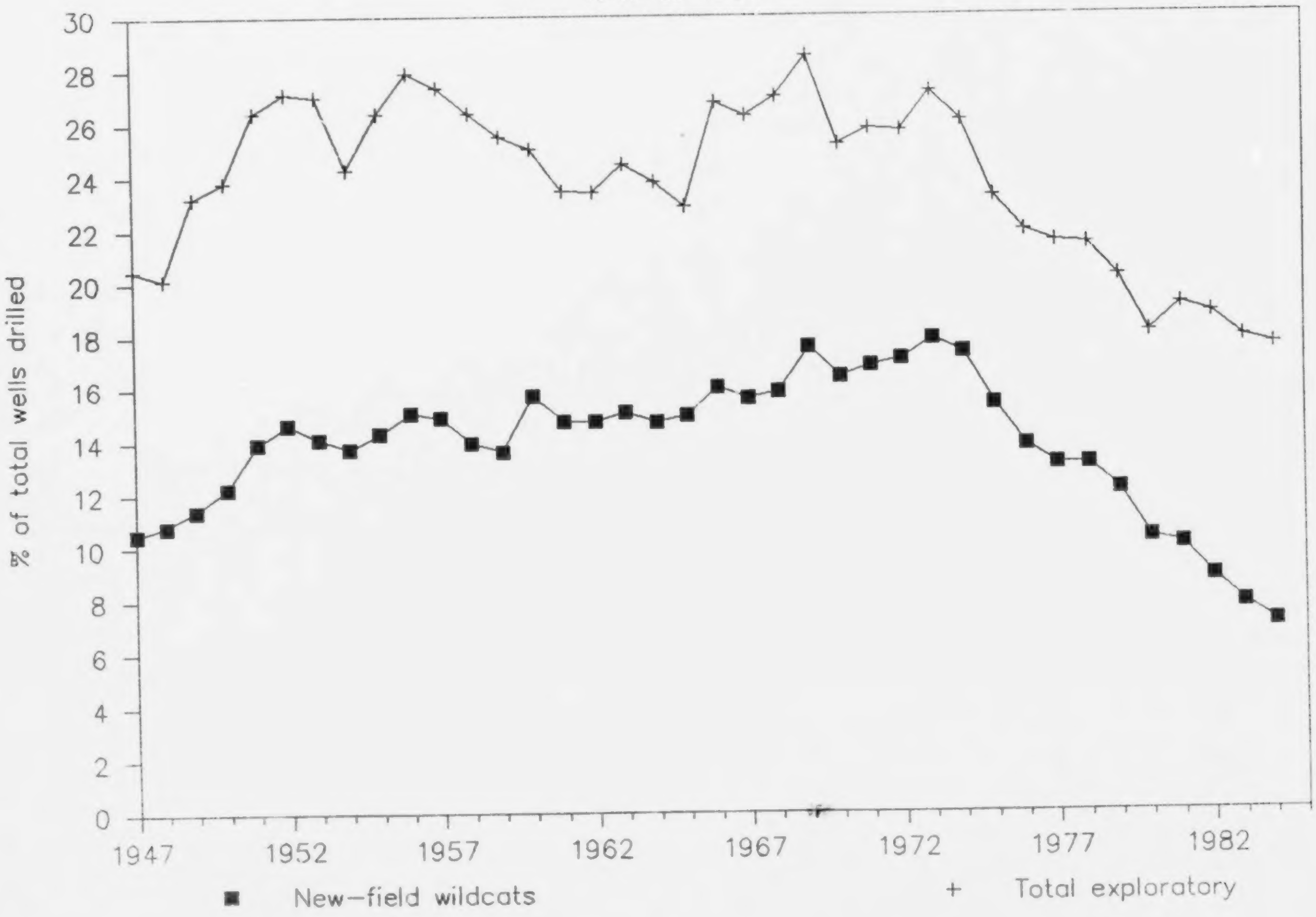


Exhibit E.8

Ratio of exploratory wells to total

1947 to 1984



1985. The GRI analysis shows that "the major decline in the discovery rates of large new oil and gas fields in the lower-48 United States appears to have ended by the early 1960s."[4]

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[4] Thomas J. Woods, "Long-Term Trends in Oil and Gas Discovery Rates in the Lower-48 United States," American Association of Petroleum Geologists Bulletin Vol. 29, No. 9 (September 1985), pp. 1321-1326.

INDICATORS OF FINGING RATES

Despite the conceptual problems involved in linking reserve additions to a particular year's exploration activity, there are two indicators that are simple to calculate and to understand:

- The exploratory success ratio - the percentage of exploratory wells that are either oil wells or gas wells
- Reserve discovery per exploratory well - the ratio of oil reserve discoveries in a given year to successful exploratory oil wells in that year.

While the success ratio for development wells is very stable, there appears to be a short-term decline (since 1982) in the success ratio for exploratory wells and for new-field wildcat exploratory wells (see Exhibit E.9). There may not be any long-term trend associated with this short-term decline.

Data on reserve discovery per exploratory well do not show a downward trend (see Exhibit E.10). These data are consistent with the hypothesis that finding rates have been stable since the early 1960s.

Exhibit E.9

Oil and gas drilling success ratios

Onshore and offshore U.S.

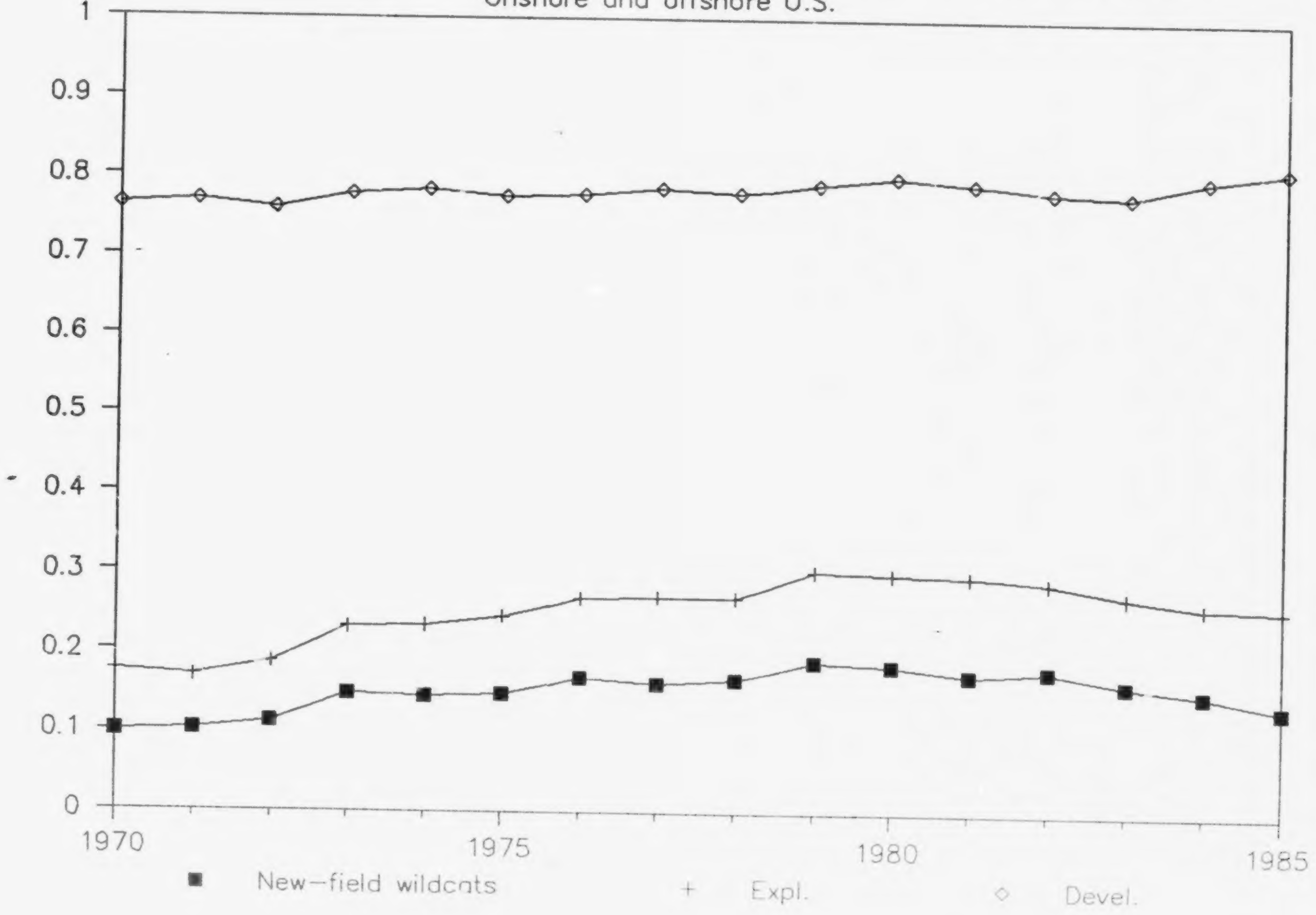
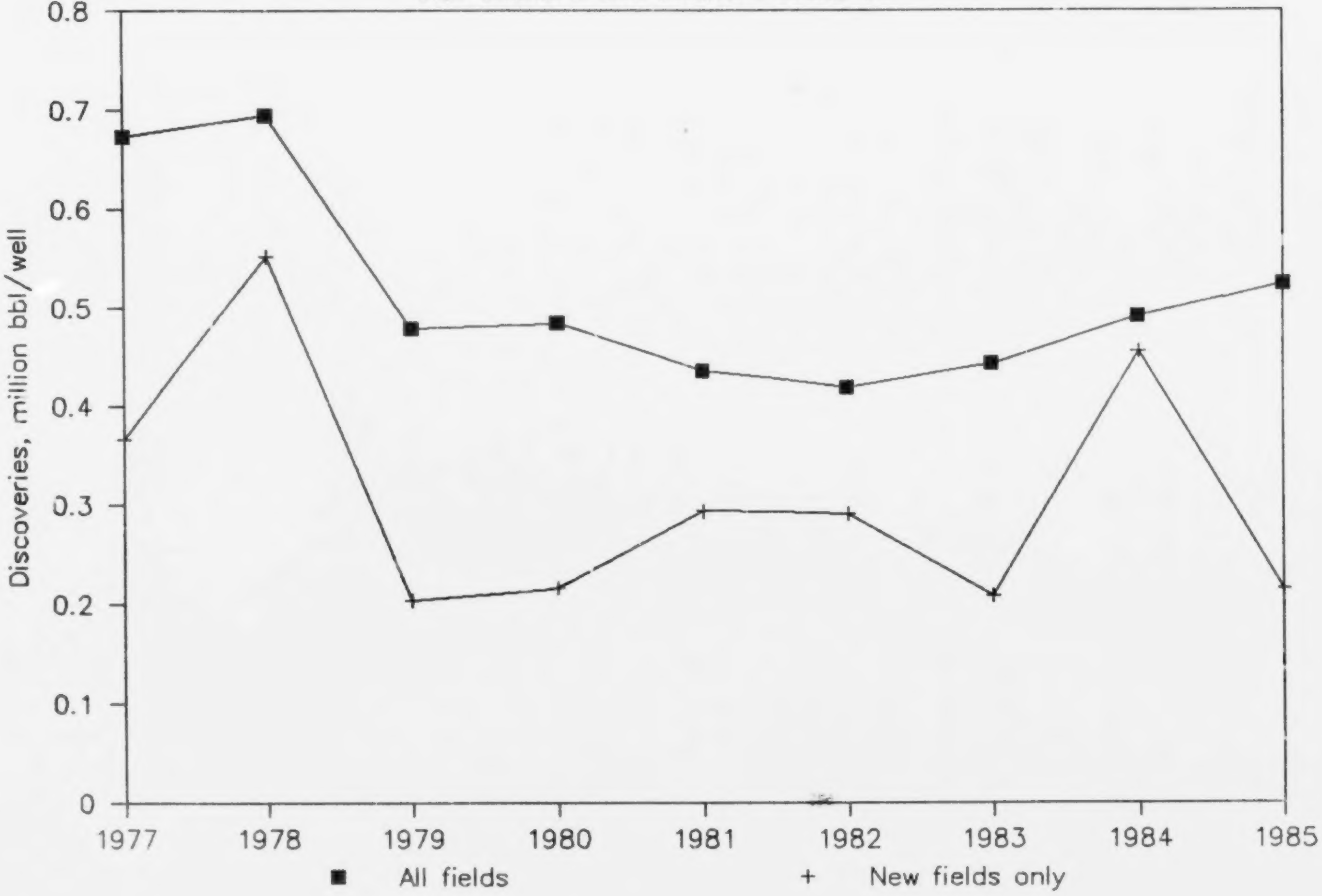


Exhibit E.10

Reserve discovery per exploratory well

U.S. onshore and offshore crude oil



THE DIFFICULTY OF LINKING RESERVE ADDITIONS TO A PARTICULAR YEAR'S EXPLORATION EXPENDITURE

Exploration expenditures include four categories of cost:

- acreage acquisition
- geological and geophysical studies
- drilling and equipping exploratory wells
- other costs, including administrative overhead.

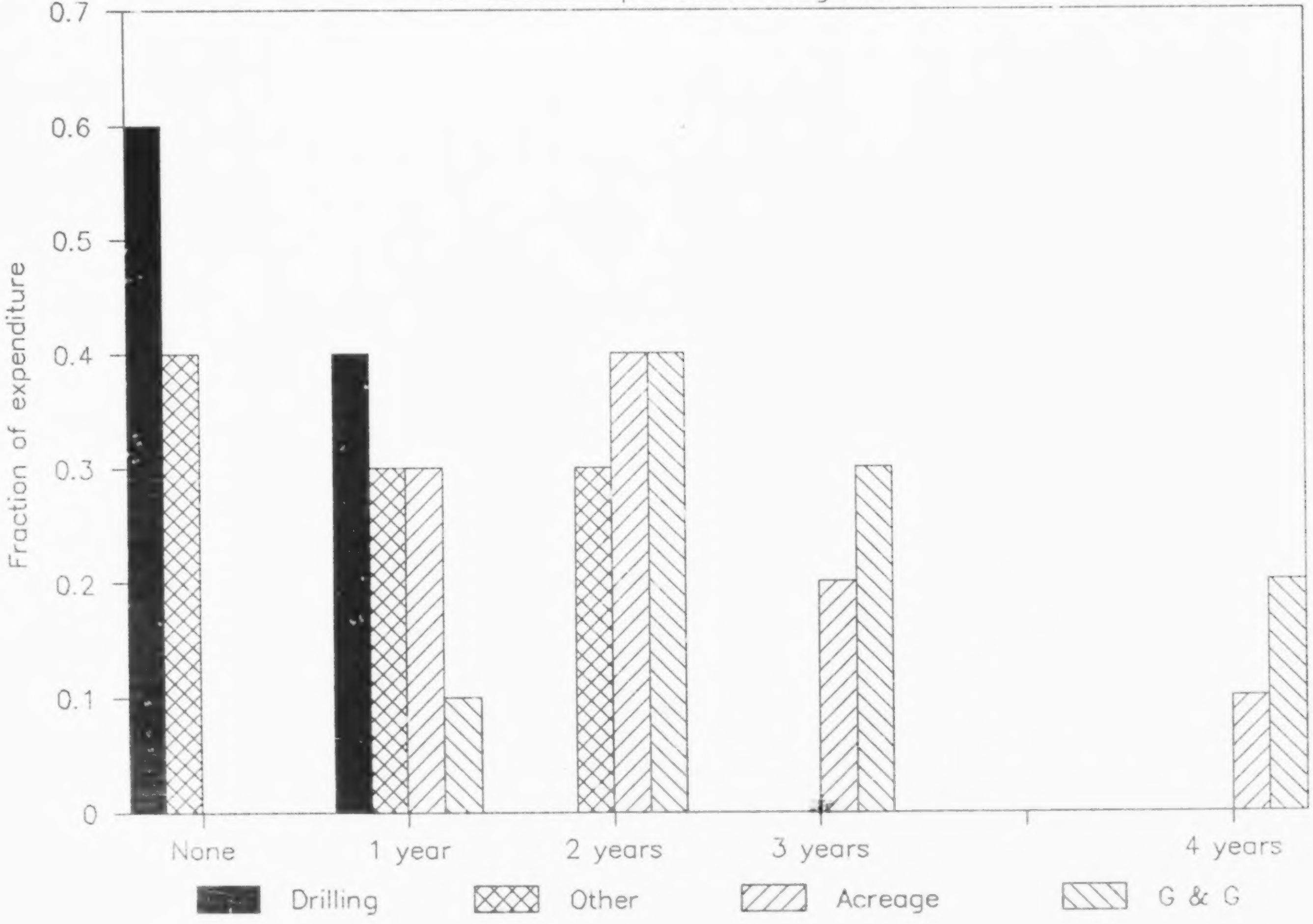
To estimate trends in finding costs - the expenditure required to find a barrel of oil in the ground - it is necessary to attribute reserve additions to expenditures in various years. Any assumptions used in this type of analysis are somewhat arbitrary. Under the set of assumptions used by the Energy Information Administration to analyze Form EIA-28 data, the longest time lags are those associated with geological and geophysical studies (see Exhibit E.11).

As oil price expectations change, patterns of exploration expenditure should change, and the time lags associated with reserve additions may change. If high oil prices are expected to be in effect by the time new reserves are brought into production, a profit-maximizing firm should be willing to explore relatively hostile environments in which finding costs are expected to be high and payoffs long-term. As oil price expectations fall, companies are likely to limit exploration to environments where finding costs are low and payoffs are short-term.

Exhibit E.11

Time lag of effect on reserve additions

for various expenditure categories



APPENDIX F

REGIONAL TRENDS IN U.S. EXPLORATORY OIL AND GAS DRILLING, 1981-1985

One way to estimate the incremental effect, on a regional basis, of Federal programs to accelerate oil exploration is to examine the changes in exploration that occurred over the 1981-1985 period, in which inflation-adjusted oil prices were falling. Because the dramatic drop in exploration activity that occurred in 1986 has no parallel in the 1981-1985 period, however, these data cannot be used to indicate the nature of a drilling recovery from the 1986 drilling activity level.

AVAILABILITY OF DATA ON EXPLORATORY DRILLING ACTIVITY

This appendix contains data on exploratory drilling activity throughout the United States. This information was collected for all states where oil and gas drilling occurred. The information was primarily obtained through the annual drilling survey conducted by the American Association of Petroleum Geologists (AAPG). Some data were also acquired through the American Petroleum Institute's databases on drilling activity. The AAPG survey was the only source identified where detailed drilling information was compiled on a state-by-state basis. The state data contains both onshore and offshore activity, where appropriate. State data were compiled into eight regional areas as follows:

- Alaska (containing both onshore and offshore activity).
- West Coast (comprising California, Oregon, and Washington).
- West Central (comprising Wyoming, Idaho, Montana, North Dakota, South Dakota, Arizona, Colorado, Nevada, Western New Mexico, Utah).
- East Central (comprising Tennessee, Illinois, Indiana, Kentucky).

- North East and Mid-Atlantic (comprising New York, Maryland, Ohio, Pennsylvania, Virginia, West Virginia, and Atlantic Offshore).
- North Central (comprising Nebraska, Kansas, Missouri, Wisconsin, Minnesota, Iowa, Michigan).
- South East (comprising Alabama, Florida, Georgia, Mississippi).
- South Central (comprising Louisiana, Texas, Eastern New Mexico, Oklahoma, and Arkansas).

From these regional data, a table describing exploratory oil and gas drilling trends for the United States from 1981-1985 was compiled. Exhibit F.a illustrates the changes in drilling activity which occurred between 1981 and 1985 as a result of falling oil and gas prices. For each region and each year, Exhibit F.1 contains the following information:

- the percentage of exploratory well completions that were successful oil wells
- the total number of exploratory wells
- the average depth of oil wells completed
- description of changes in drilling activity, with special reference to changes determined by economic conditions.

ANALYSIS OF DATA ON DRILLING ACTIVITY

For each region the trends in the exploratory drilling and the disparities between the databases may be illustrated graphically (see Exhibits F.2 through F.9). In the North East and Mid-Atlantic region, both AAPG and API show steadily declining drilling rates for the region in the 1981-1985 period; however, the total number of exploratory wells drilled differs by more than ten percent, with AAPG showing a higher count. It appears that there may be a definitional difference between these two sources of data. The AAPG drilling survey is performed annually.

It is apparent that as oil and gas prices dropped, drilling activity in the marginal regions like the North East and Mid-Atlantic, and South East declined steadily. In active production areas, such as the South Central region, the trend

Exhibit F.1
Page 1 of 11

Year	Region	Oil Wells as a Percent of Exploratory Well Completions - (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1981	Alaska	100 (3)	33	10,263	- Slight increase in exploration drilling.
					- Roughly two thirds of all exploration wells were drilled on the North Slope.
					- Activity in the rest of the state hit its lowest point in years. Uncertainty over exportation of natural gas to the lower 48 states has effected drilling activity.
	West Coast	NA	565	2,146	- Drilling in California increased by about 10%. Offshore activities were centered on the Santa Barbara Channel.
					- Elsewhere in region, drilling increased slightly.
	West Central	NA	3,193	6,526	- The Denver-Julesburg Basin was the target of exploration in Colorado. Exploratory drilling increased dramatically with 65% rise in the number of wells drilled over 1980 levels.
					- Drilling was up in the remainder of the region. In the 4 Corners area, the Utah Overthrust Belt was the center of successful drilling activity.
	East Central	74	2,394	1,890	- Exploratory activity varied by state within the region. In Tennessee, exploratory drilling was off by 4%, however, Illinois recorded an increase of 48%. Kentucky and Indiana showed slight increases in activity.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1

Year	Region	Oil Wells as a Percent of Exploratory Well Completions (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1981 con't.	North East and Mid-Atlantic	NA	953	2,160	- Drilling activity was up throughout the region. The depth of exploration wells was also up. However, high cost, deep drilling, particularly in areas with less potential, was subject to market trends. - Southeastern West Virginia is likely to continue to be the target of future exploration activities.
	North Central	75	2,201	3,757	- Activity was up throughout the region. - In Michigan, emphasis was placed on drilling deeper exploratory wells. Niagaran reef exploration was still the primary focus of most activity. Continued drilling at greater depths is expected in 1982.
	South East	40	415	8,974	- Drilling increased by 11% in this region. The leading drilling area was the shallow Eocene Wilcox trend in Southwestern Mississippi. - A decline in activity is expected in 1982, particularly with regards to ultra deep gas drilling because of the uncertainty in market conditions.
	South Central	41	5,282	4,371	- Drilling activity was brisk in the region. In some areas, a shortage of rigs limited the number of wells drilled. - Price decontrol spurred wildcat drilling and an increase in the depth of drilling.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1
Page 3 of 11

Year	Region	Oil Wells as a Percent of Exploratory Well Completions - (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1982	Alaska	100 (1)	24	9,714	- Exploratory activities focused on North Slope, onshore and offshore (Bering Sea). - Exploratory drilling absent in the rest of the state because of a lack of available lands and uncertainty over the future gas market.
	West Coast	NA	508	2,864	- Brisk drilling activity for onshore California. Roughly half of all exploration took place in new pool and field areas. - Trend in Oregon and Washington was toward wildcat drilling at greater depths, but this was only 2% of all drilling for the region. - Offshore drilling focused on the Santa Maria Basin. Four new offshore discoveries were made.
	West Central	NA	2,183	6,063	- Drilling dropped off in this region largely because of the drop in oil prices in the second half of the year.
	East Central	73	2,228	1,861	- Oil and gas leasing continued at a rapid pace in Tennessee - Drilling activity declined by 3% in Illinois; attention was given to drilling at greater depths; most activity is expected to focus on in-fill drilling and extension of old production.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1
Page 4 of 11

Year	Region	Oil Wells as a Percent of Exploratory Well Completions (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1982 con't.					- Increased drilling activity in Indiana centering on the Renault Formation. - Drilling increased in Kentucky; however, this may not be sustained as a result of the depressed natural gas market.
	North East and Mid-Atlantic	NA	758	2,450	- Exploratory drilling in New York focused on the Western and Central sections of the state. Important gas discoveries were made; however, the future of further drilling is questionable during this period when gas is being shut-in and gas purchasers put a 5 month moratorium on gas purchases. - Largest number of exploratory wells was drilled in Ohio, but these were at shallow depths, largely extensions of existing production. Activity was brisk in the Virginia Overthust, where deeper drilling is required. - Because of the severe slow-down in the energy industry, drilling in Pennsylvania decreased by 47%.
	North Central	79	2,897	2,898	- Drilling was scattered in Kansas. - Most of the drilling in Nebraska occurred in new-field wildcats, while drilling in Missouri was mostly extensions of old production.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1

Year	Region	Oil Wells as a Percent of Exploratory Well Completions - (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1982 con't..					- Drilling in Michigan was concentrated in the Northern part of the southern peninsula. Continued activity likely to taper off with the decline in crude oil and natural gas prices. Other noted factors influencing drilling at this time were interest rates and government regulatory practices.
	South East	41	333	10,429	- Mississippi was the must active state in drilling. Twenty-four new-field discoveries were made. - Exploratory drilling will continue to decline in the region. Deep exploration at the 15-20,000 ft. range for natural gas will reach a low because of economic conditions.
	South Central	43	6,046	4,398	- Slight increase in offshore drilling activity after a 6-year low in 1981. - 20% increase in exploratory drilling in the Permian Basin, mainly in mature areas. - In Oklahoma, deep drilling increased significantly with 16 wells drilled below 20,000 ft. - East Texas drilling should maintain stable levels, despite declines in other areas of Texas.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1
Page 6 of 11

Year	Region	Oil Wells as a Percent of Exploratory Well Completions (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1983	Alaska	0	11	9,413	- Exploration activities were primarily targetted to the North Slope and Beuafort Sea. - Second year that exploration declined in Alaska.
	West Coast	NA	217	2,307	- Drilling activity declined sharply in the region.
	West Central	NA	1,453	6,073	- Dramatic decline in drilling activity based on declining oil prices. - Greatest activity took place in the Powder River and Williston Basins. - Oversupply of natural gas suppressed drilling in basins that are predominantly natural gas.
	East Central	59	2,452	1,775	- Mainly, in-fill and extension drilling was conducted in Illinois, and activity is likely to remain high. - Activity in Indiana was fairly active and indications forecast little change in trend. - Slight increase in activity in Kentucky in 1983.
	North East and Mid-Atlantic	14	550	2,543	- Exploratory drilling in the region was down by 28%. Activity centered around shallower resources since shut-ins of gas production continued.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1
Page 7 of 11

Year	Region	Oil Wells as a Percent of Exploratory Well Completions (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1983 con't.	North Central	77	2,254	2,826	- Pinnacle reef exploration continued to dominate drilling activity in Michigan. - No significant change in regional drilling activity from the previous year, except for the drop in total wells drilled.
	South East	52	357	9,041	- Exploratory drilling increased by 7% over 1982 levels. Forty percent of this drilling occurred in the shallow Eocene Wilcox trend in Southwest Mississippi. - The bulk of this drilling is likely to be conducted by independents and small companies.
	South Central	45	6,718	4,443	- Drilling activity trends differed throughout the region; however, a shift from gas to oil prospects began to emerge as a result of economic constraints in the gas market. - Some operators took advantage of depressed rig prices and maintained oil exploration activities.
1984	Alaska	100	35	8,427	- The greatest number of exploratory wells drilled since 1966. - Activities were primarily focused on the North Slope, Cook Inlet Basin, St. George Basin, Norton Basin, Beaufort Sea, and Tanana Basin.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1
Page 8 of 11

Year	Region	Oil Wells as a Percent of Exploratory Well Completions (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1984 con't.	West Coast	NA	261	2,016	- Onshore activity in this region reached near record levels, but offshore activity dropped off significantly.
	West Central	NA	1,541	6,720	- Exploratory drilling increased for the region. Areas of greatest activity continued to be the Powder River and Williston Basins. - Exploration in Colorado focused on deeper, less conventional plays.
	East Central	84	1,970	1,820	- In Tennessee, drilling activity was down, but the activity that did take place occurred mainly on the Cumberland Plateau. - Both Kentucky and Indiana witnessed a decline in
	North East and Mid-Atlantic	NA	350	2,533	- Activity has remained fairly constant off the Outer Continental Shelf over 2 year period. While the number of wells drilled has remained constant, depth of drilling has increased. - Major exploration activity in New York has centered an extensions of Medina Tight Formation gas-fields. Gas surplus has caused operators to shut-in half of production capabilities. - Overall, there was a decline in exploratory drilling throughout the region.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.1
Page 9 of 11

Year	Region	Oil Wells as a Percent of Exploratory Well Completions (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1984 con't:	North Central	82	2,926	3,032	- Exploration activity changed very little in Michigan except for an increase in the depth of drilling. - Drilling for oil was actively pursued in Kansas. Nebraska also experienced an increase in drilling, but in the remainder of the region drilling declined.
	South East	45	364	10,161	- Exploratory drilling increased by only 2% in this region. - Majors and independents have centered their activity on Upper Cretaceous and Jurassic trends. - Uncertain gas markets are likely to restrain further activity in the Lower Cretaceous gas play, which represented 6% of total exploratory drilling in 1984.
	South Central	56	6,713	4,352	- As a result of low oil prices, exploratory drilling held steady, targetted mainly on shallow, less costly pay zones. - Activity has remained steady because of a decline in exploration costs. - A conservative drilling strategy has been adopted by most companies, concentrating on extensions and exploration drilling in established trends.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Year	Region	Oil Wells as a Percent of Exploratory Well Completions (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1985	Alaska	11	35	7,842	- Highlight of year's explortory drilling was the new areas tested. - Areas explored were the Beaufort Sea, North Slope, St. George Basin, Norton Basin, Navarin Basin, Bristol Bay Basin, and Cook Inlet Basin. - At end of 1985, no plans for further wildcat drilling were announced. With declining oil prices, activity is expected to drop off.
	West Coast	NA	265	1,897	- Drilling activity remained steady in 1985. - Exploration in off-shore areas continued to decline. - Onshore activity was brisk, with increased drilling in Washington and Oregon.
	West Central	20	2,604	6,371	- Four Corners region experienced a sharp recovery in 1985. Preference for oil exploration. - The northern rockies experienced a similar rise in activity. Oil-productive basins like the Powder River and Williston saw the greatest activity.
	East Central	20	2,240	1,808	- Drilling in this region increased slightly in 1985. - In Tennessee, the decline in drilling has been a continuing trend since 1981.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Year	Region	Oil Wells as a Percent of Exploratory Well Completions - (%)	Total Exploratory Wells	Average Depth of Oil Wells Completed (feet)	Comments
1985 con't.	North East and Mid-Atlantic	3	355	3,266	- Drilling declined in New York in 1985 and this trend is expected to continue through 1986. If exploratory drilling takes place in 1986, it will be concentrated in safe areas.
					- Activity in the rest of the region was stable. Drilling was focused primarily on shallower pools. Oil prices dropped significantly in the region within the first 6 months of 1986 and exploration is expected to be curtailed severely in 1986.
	North Central	17	2,630	3,080	- In Kansas, exploratory drilling declined. Traditional areas in shallow locations suffered a big drop.
					- Drilling in Nebraska and Missouri also declined.
	South East	10	410	9,335	- Total number of exploratory wells was the highest amount since 1981 when 415 wells were drilled. This is considered exceptional considering the "state of the market." The trend is not expected to continue in 1986. Independents are likely to continue to go after shallower reserves while the majors pursue deeper ones.
	South Central	13	5,922	4,331	- Exploratory drilling rose slightly in the Permian Basin and was focused on mature areas. Drilling declined in the rest of the region.
					- Movement away from high cost, high risk deep drilling.
					- Activity in the gas provinces of the region are expected to decline with the current glut of resource.

Key: NA - Not available

Sources: American Association of Petroleum Geologists. North American Drilling Activity Survey.
American Petroleum Institute. United States Drilling Statistics Annual Completions, 1985.

Exhibit F.2

Total exploratory wells in Alaska

1981 to 1985

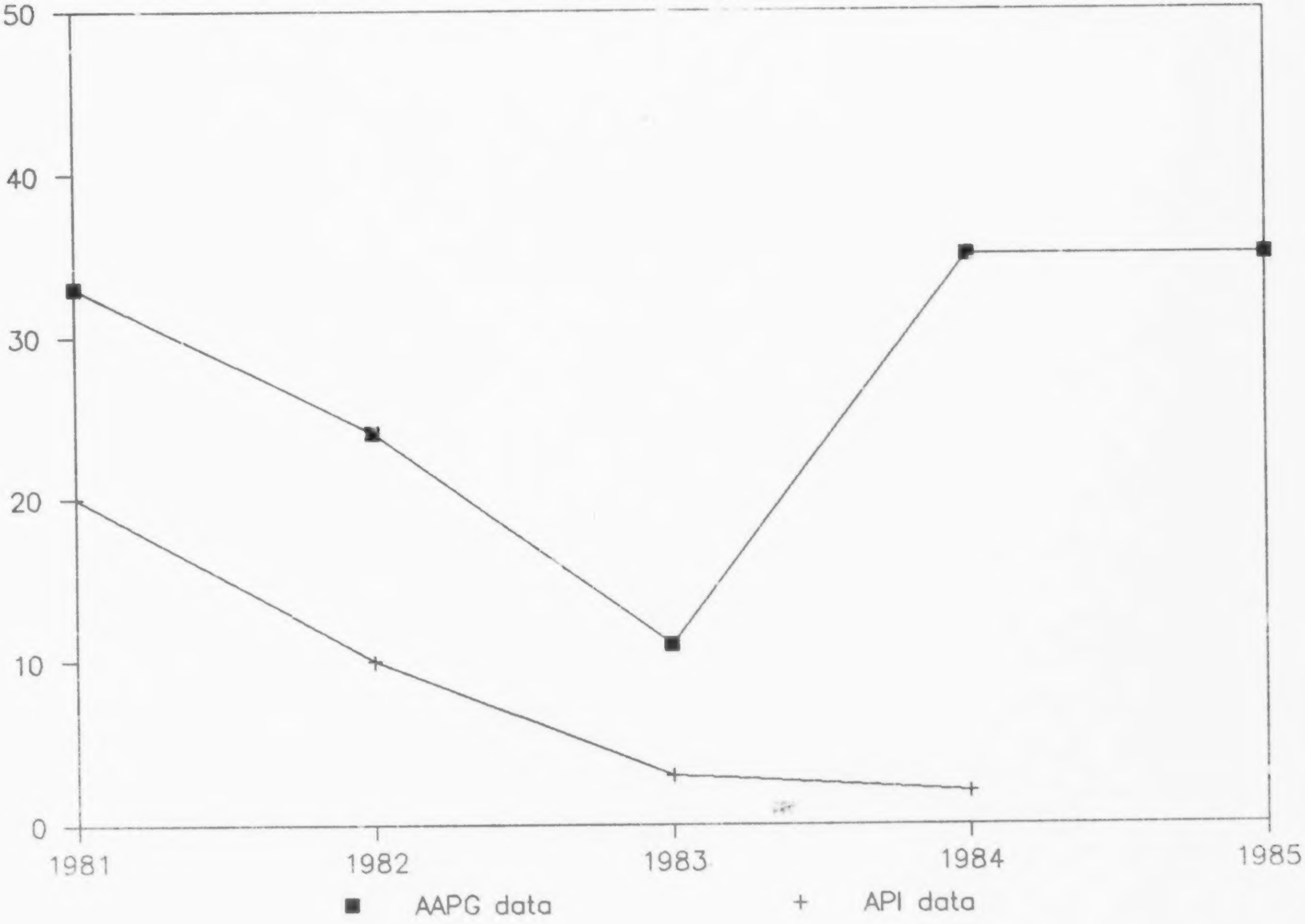


Exhibit F.3

Total exploratory wells in the West Coast Region

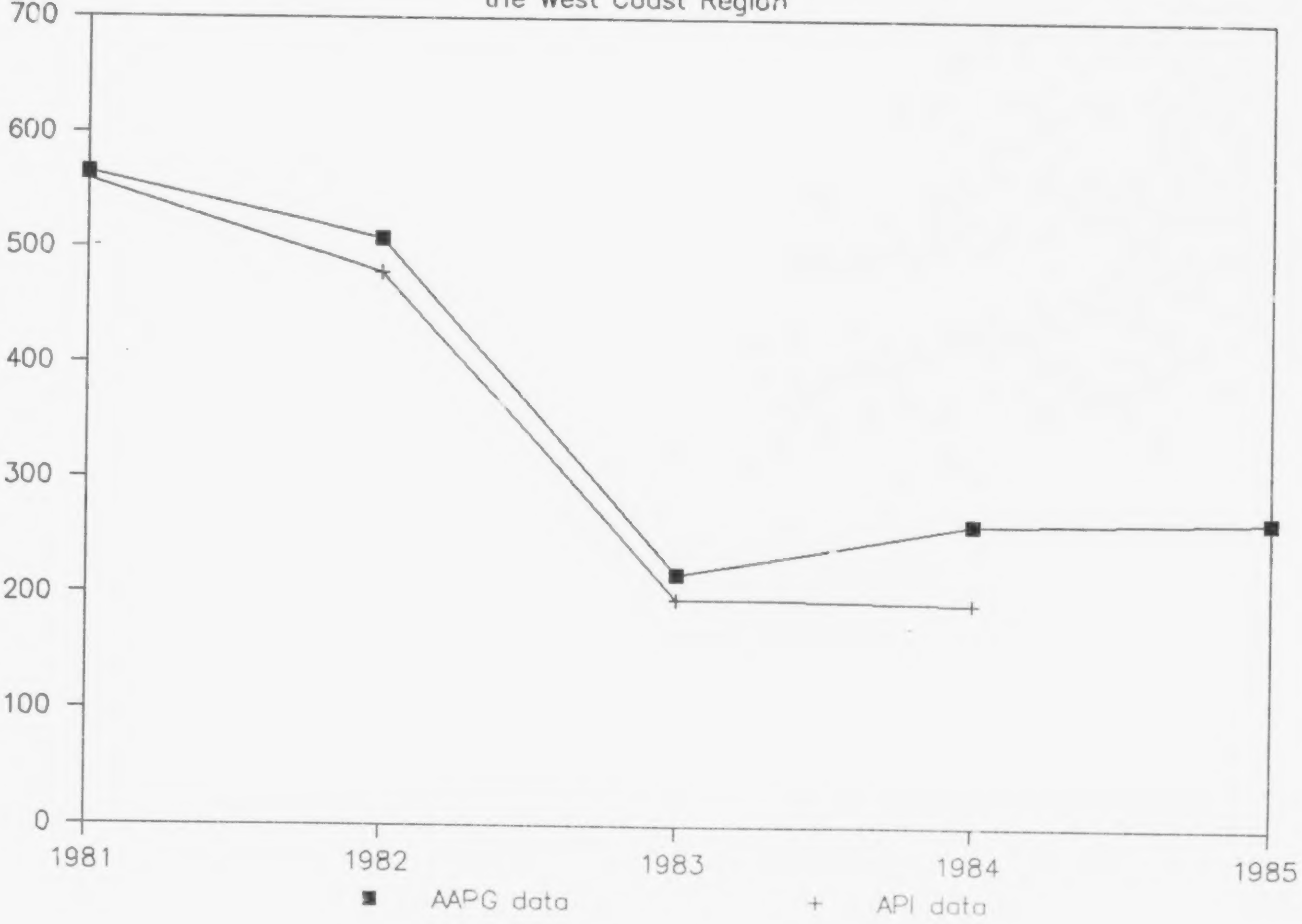


Exhibit F.4

Total exploratory wells in
the West Central Region

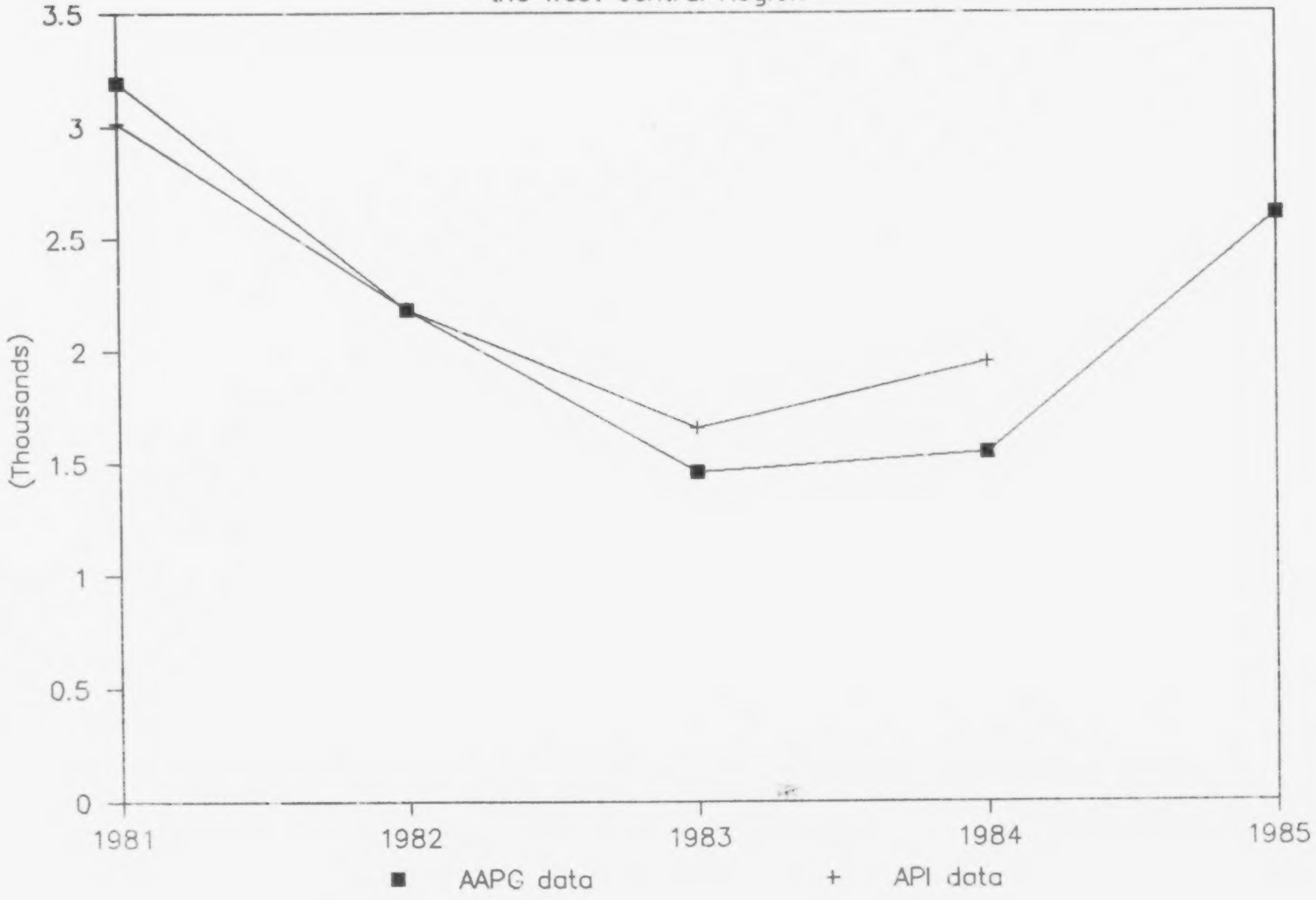


Exhibit F.5

Total exploratory wells in

the East Central Region

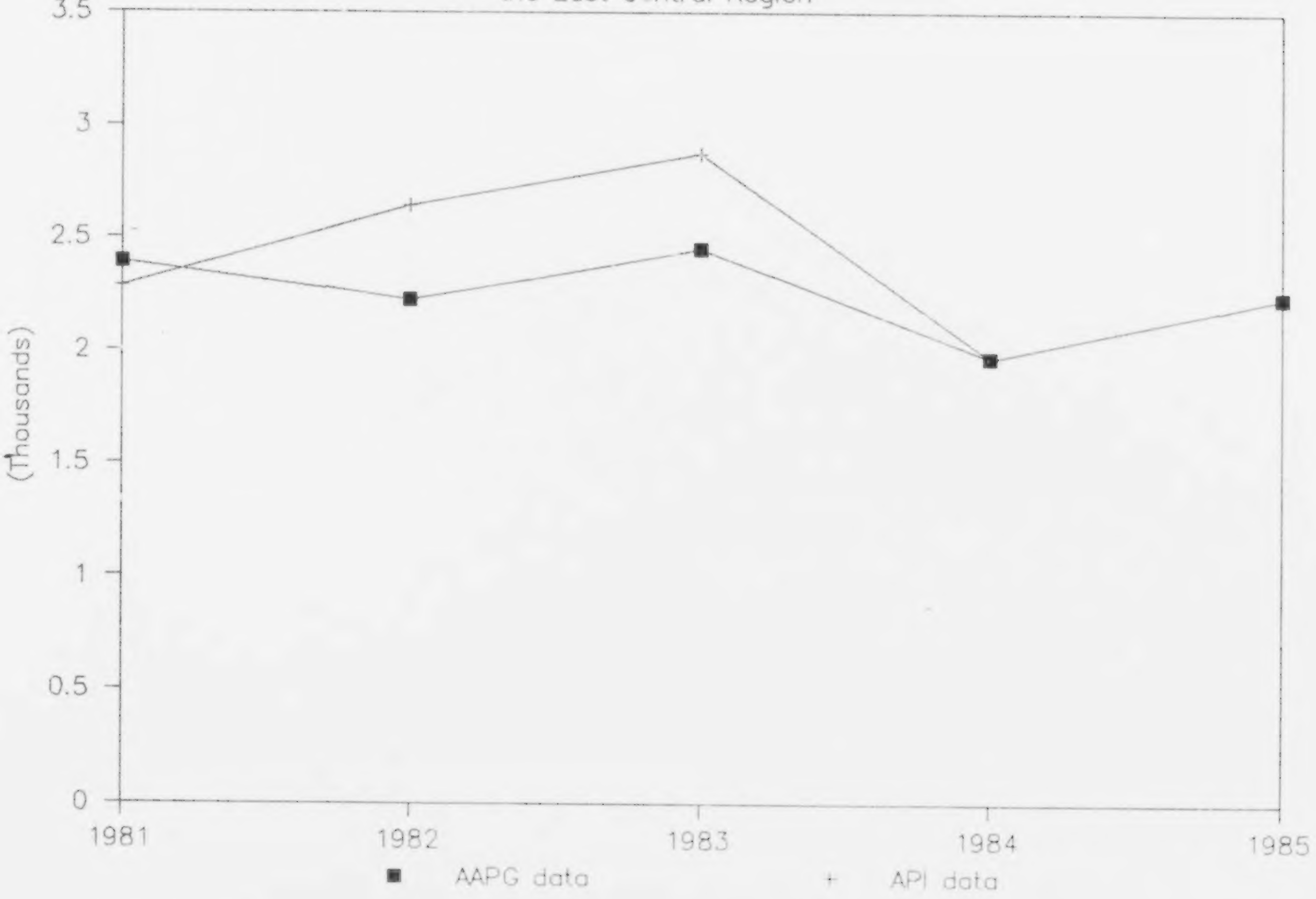


Exhibit F.6

Total exploratory wells in the

NE–Mid Atlantic Region

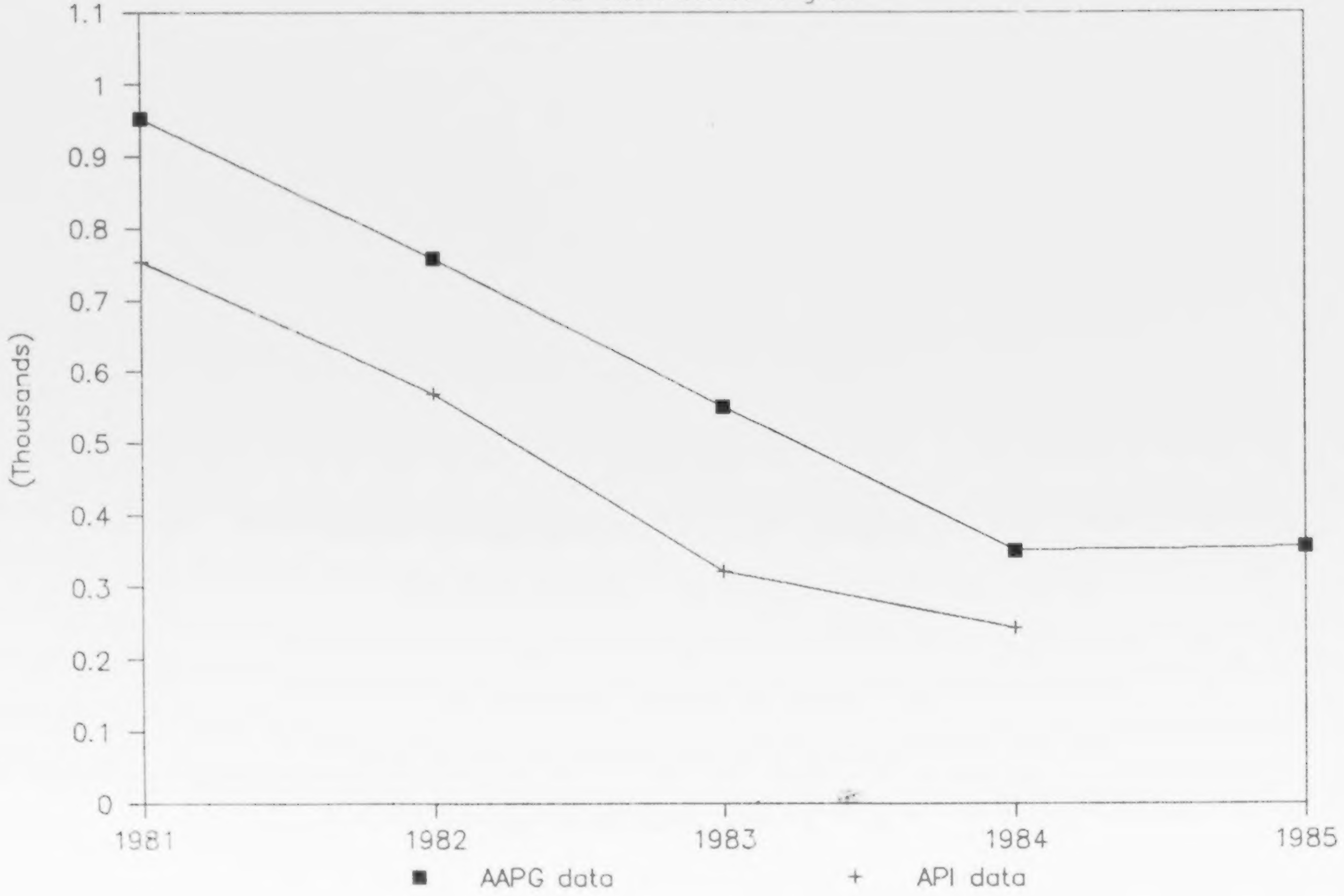


Exhibit F.7

Total exploratory wells in

the North Central Region

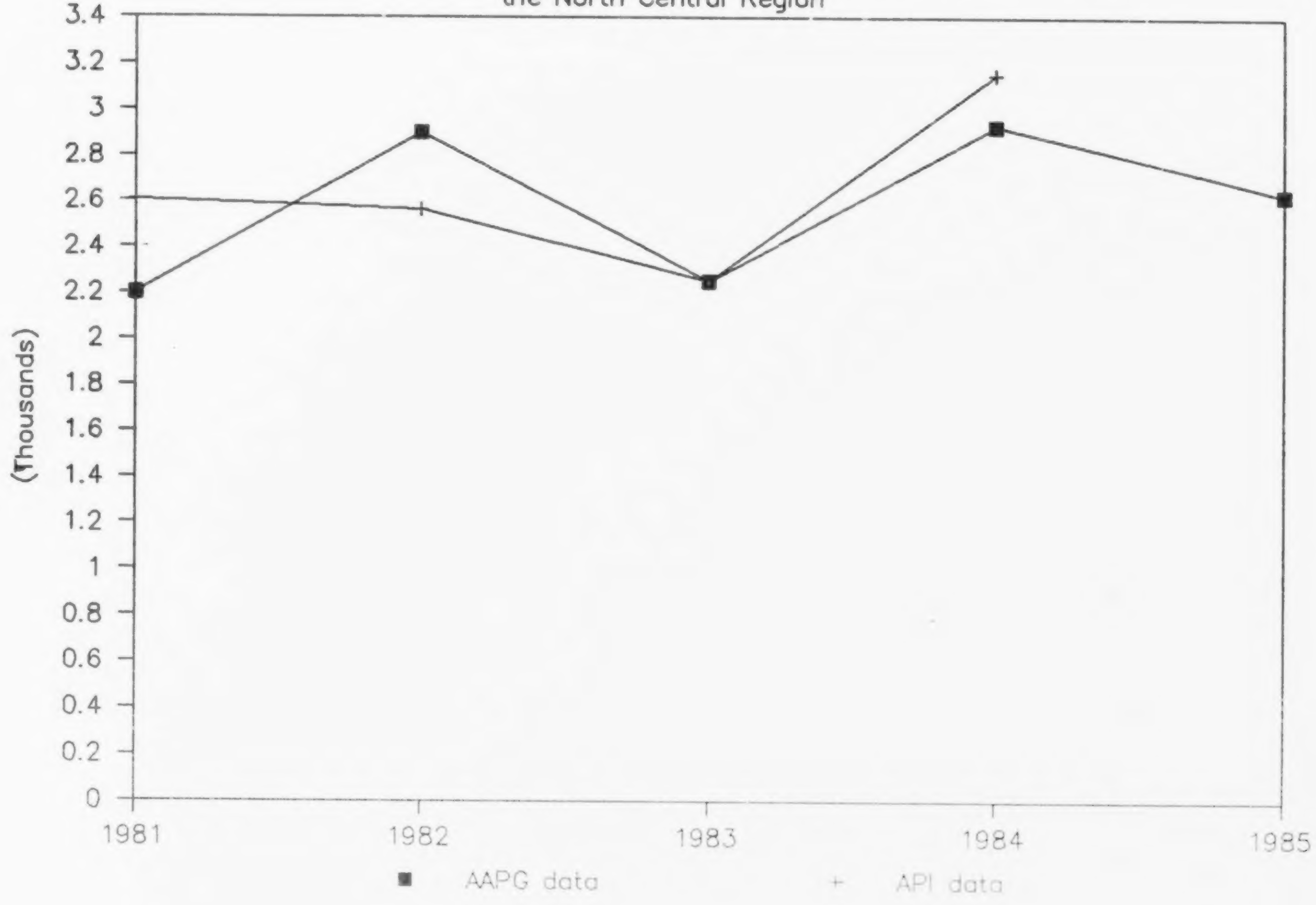


Exhibit F.8

Total exploratory wells in

the South East Region

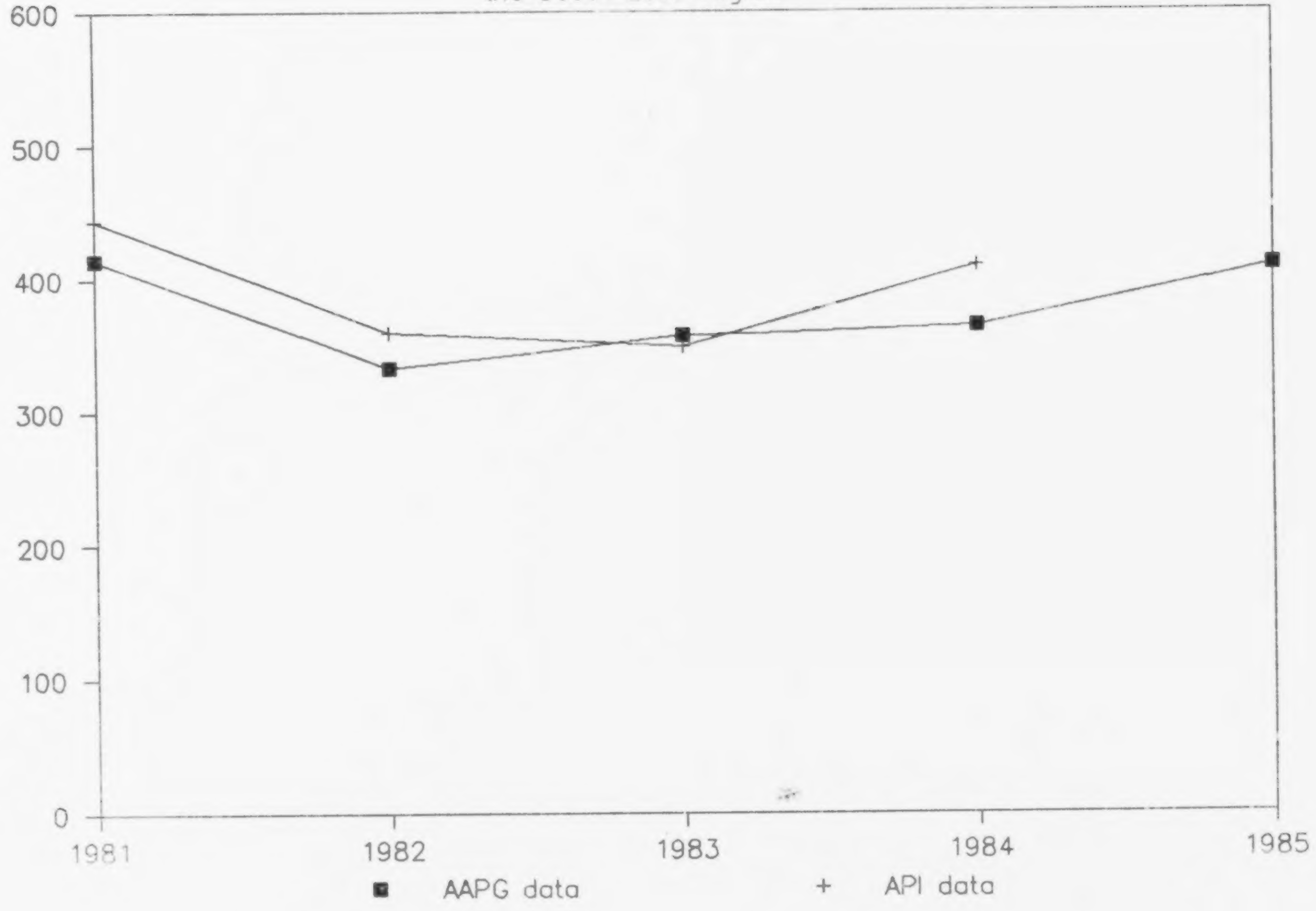
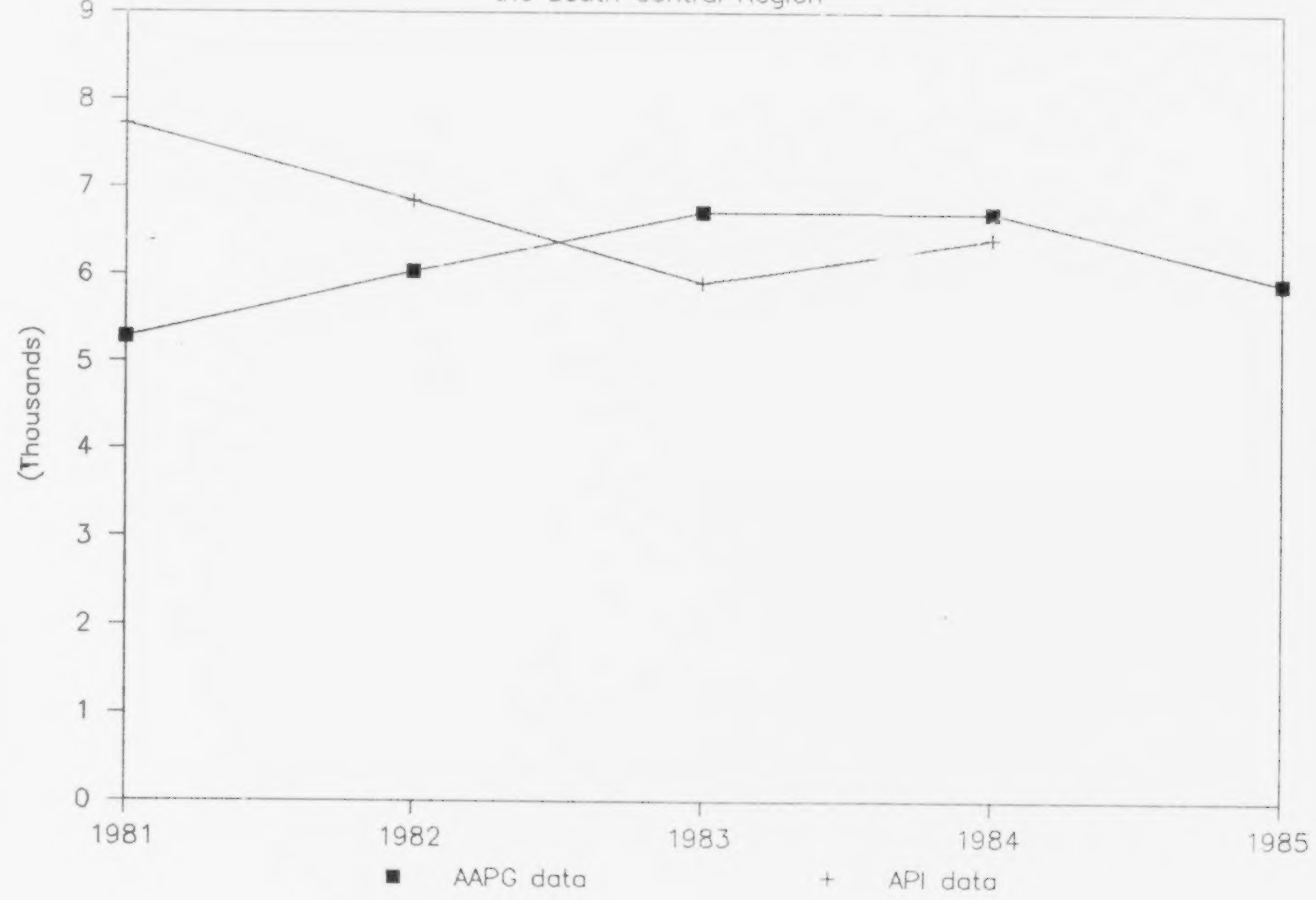


Exhibit F.9

Total exploratory wells in

the South Central Region



is unclear, although it appeared to fall off in 1985. For the large producing regions, the initial drop in oil prices caused shifts in the type of drilling activity conducted rather than the actual number of rigs. For example, during the 1982-1983 time frame, exploratory drilling began to shift toward known areas rather than frontier regions like the Overthrust Belt. In some areas of Oklahoma and Texas, operators took advantage of the drop in rig costs and drilled more actively in well-known regions. However, as oil prices continued to fall, there is a trend toward no growth or actual declines in drilling activity even in the most active producing regions.

In Exhibits F.10 and F.11, graphs depicting total drilling trends for both AAPG and API are presented along with a comparison among trends in the most active regions. Although the total number of rigs drilled differs between data sources, the Oil and Gas Journal, API, and AAPG show a vacillating trend in the 1981 to 1984 period, but indicate a steady decline after 1984.

The Oil and Gas Journal reported different totals for exploratory drilling throughout the period. The Oil and Gas Journal in its semi-annual forecast of drilling activity has forecast for 1986 a total of 6,987 well completions. This is severe drop in drilling when compared with AAPG 1985 drilling total.

AVAILABILITY OF DATA ON RESERVE ADDITIONS

Disaggregated data on crude oil reserves by state are reported in EIA's annual reserve report but are not available for all the states recorded in the AAPG drilling survey. The following states have recorded some drilling activity, but are not explicitly identified in EIA crude oil reserve data:

Arizona
Georgia
Idaho
Iowa
Maryland
Minnesota
Missouri
Nevada
Oregon
South Dakota
Tennessee
Washington
Wisconsin.

Exhibit F.10

Total exploratory wells

All Regions (AAPG data)

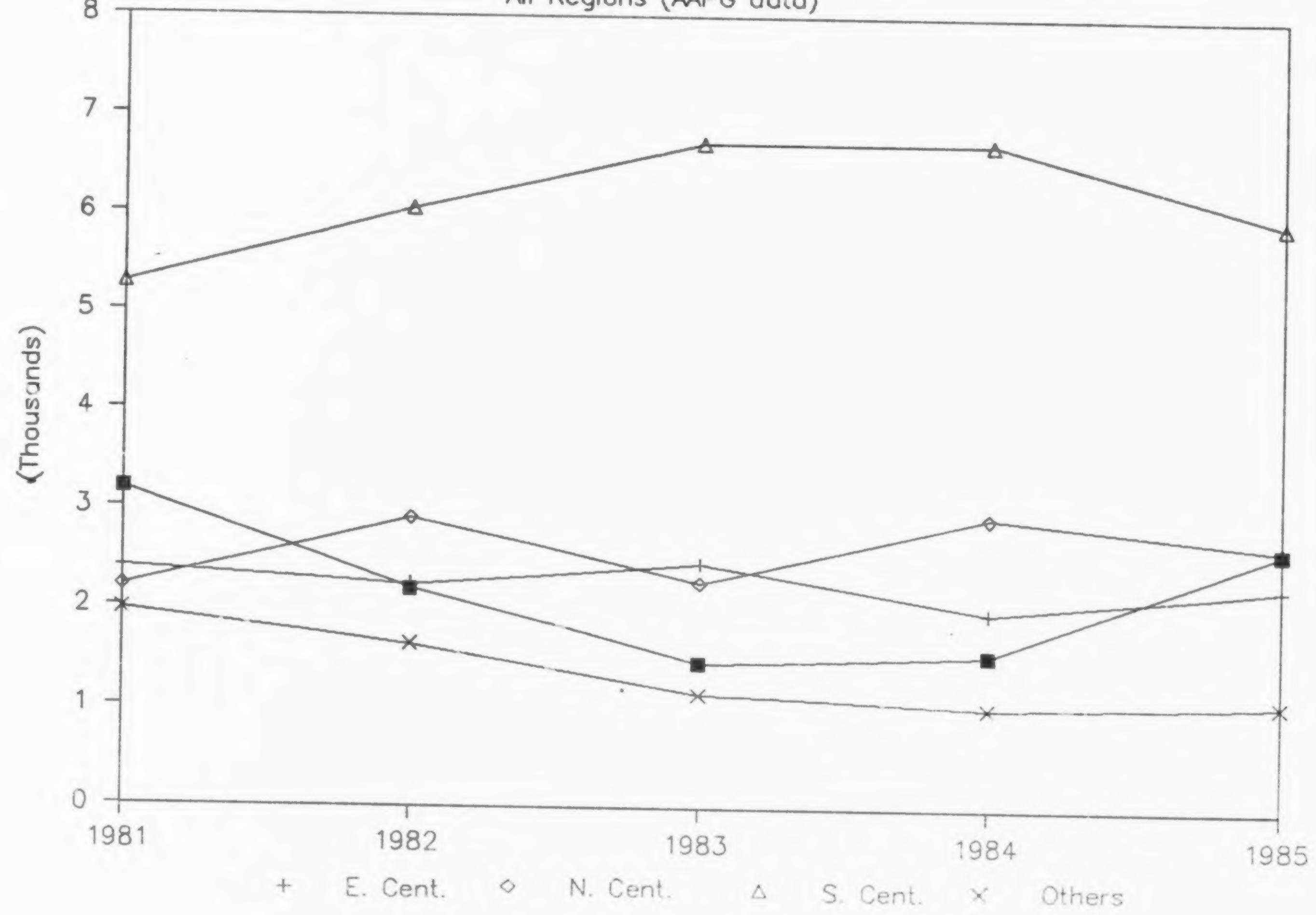
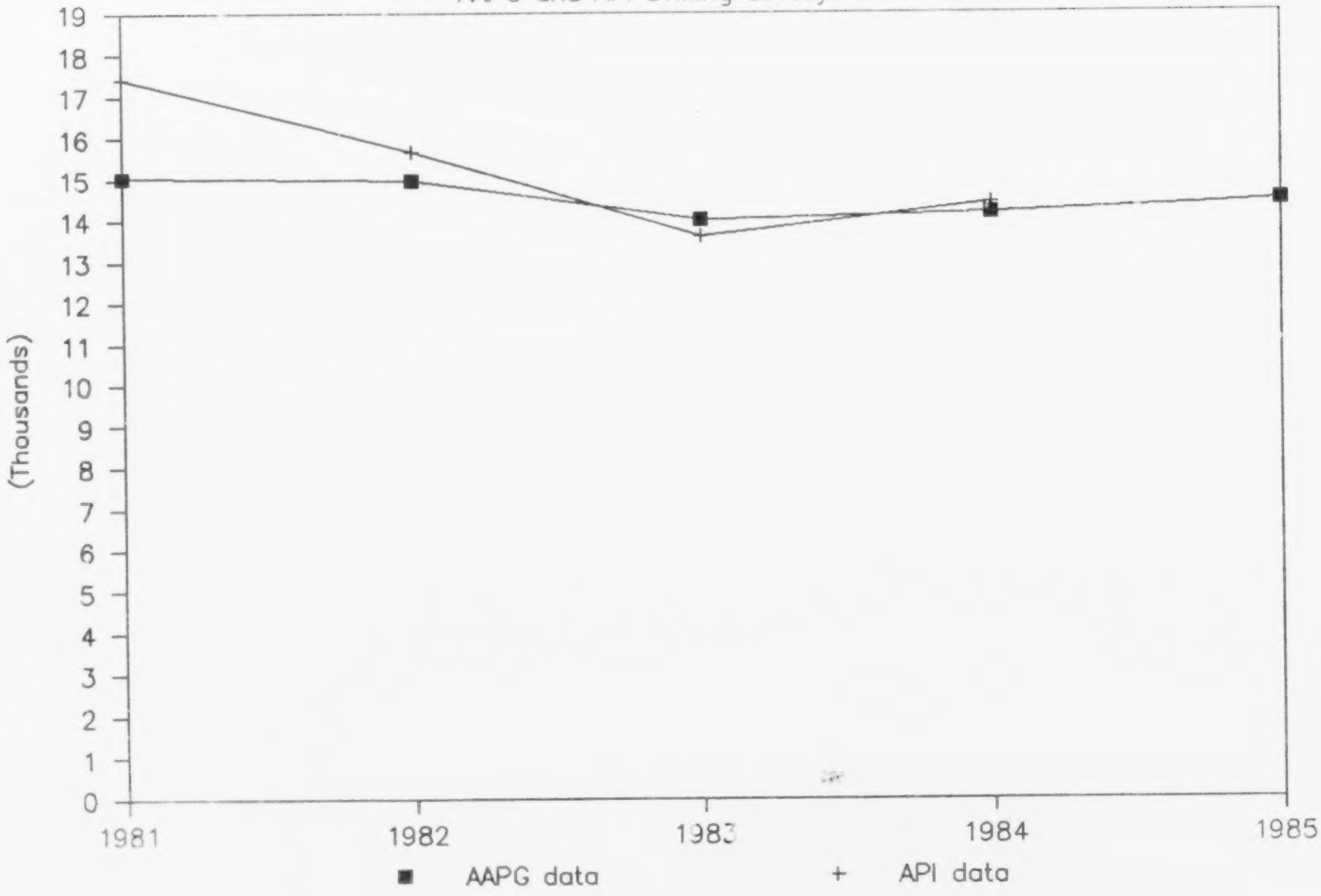


Exhibit F.11

U.S. total exploratory wells

AAPG and API Drilling Surveys



APPENDIX G

SUMMARY OF INCENTIVE PROGRAMS IMPLEMENTED BY ALBERTA, CANADA

In 1986, exploration and development activity in the province of Alberta dropped to about one third of the 1985 levels. In an attempt to stimulate exploration and development, the province of Alberta enacted several incentive programs. The purpose of the programs was to provide companies assistance and incentives to drill more new wells. All incentives apply only to companies that drill on crown land.

The incentives programs enacted were: Development Drilling Assistance Program, Exploratory Drilling Assistance Program, Well Servicing Assistance Program, and the Geophysical Assistance Program. In addition to these incentive programs that provide direct financial assistance for exploration and development, the Alberta government also instituted the Crude Oil Royalty Program, which provides a royalty holiday period for production from new qualifying wells. Although this program does not provide immediate financial support for drilling new wells, it is designed to increase the prospective financial returns from new drilling and thereby encourage additional exploration and development activity. These programs are discussed in the following sections.

DEVELOPMENT DRILLING ASSISTANCE PROGRAM (DDAP)

The Alberta government allotted 100 million dollars for this program, which ran from June to December 1986. Development wells spudded after June 3, 1986 and before January 1, 1987 on lands owned by the Province of Alberta (crown lands) were eligible for assistance. The purpose of DDAP was to encourage companies to drill new development wells in areas known to have oil. These wells were not exploratory wells. The program was operated on a first-come, first-served basis until the obligated funds had been exhausted.

Under this program, the Alberta government would rebate a specified dollar amount per well depending on the well's depth and location. Participating companies had the choice of receiving a credit against future royalty payments to the Alberta government or cash. All companies chose cash. No money was received for wells drilled to a depth of 400 meters or less. Below 400 meters, the incentive amount per well increased with each 200 meters drilled. The location of the well also influenced the incentive amount. Wells drilled in the prairie region, where it is more expensive to drill because of mountains, received a larger incentive than those drilled in the plains. The average percentage of development well cost shared by the government amounted to about 40 percent.

There were 3 stages in receiving incentive funds under the DDAP:

1. **Confirmation of Eligibility.** The company applied to the Department of Energy for an incentive approval based on the depth and location of the well to be drilled. If the application was approved by the Department, the company was assigned a specified number of dollars to be received upon fulfillment of the drilling program (discussed below). The company then had ten days to spud the well. If the well was not spudded within ten days, the company lost its funds approval and had to reapply. Running the program in this way achieved two benefits. First, by preliminarily qualifying wells for the incentive, firms were able to operate with full certainty of receiving the obligated funds after completing the drilling activity. Second, by requiring that a well be spudded within 10 days of granting the incentive approval, the Department was able to prevent firms from tying-up the limited program funds for future wells and could monitor closely the availability of funds.

2. **Drilling Component Application.** After a company had drilled its well, it submitted a DDAP-VI Application for Drilling Component form, which confirmed the actual depth drilled, and was used to determine the actual assistance available according to the schedule. This application was to be submitted within 90 days of the finished drill date. The grant was split into two parts for the drilling component: the company received 70% after drilling the well, 30% when and if the well was completed. Funds were not released to the company until it had paid all outstanding charges for drilling the well. Incentive funds were released to companies within 45 days of the submission of a complete Drilling Component Application.

3. **Completion Component Application.** If a well was completed (i.e., prepared for production), the company submitted

a DDAP-V2 Application for Completion Component form. This form confirmed the actual completion of the well and was used to determine the final amount of incentive according to the schedule. DDAP-V2 had to be submitted within 180 days of the finished completion date. Within the 180 days, the company had to have paid all invoices. The government then verified the depth and location of the drilling activity and made the approved final payment within the allotted 45-day period.

EXPLORATORY DRILLING ASSISTANCE PROGRAM (EDAP)

The purpose of EDAP, which began January 4, 1986 and ended December, 1986, was to encourage companies to drill exploratory wells on crown lands. The Alberta government allotted $300 million for this program, of which $85 million was left at the end of program.

Under EDAP, the Alberta government extended royalty payment credits for 50 percent of the actual drilling cost of an approved exploratory well. Allowable costs included all direct costs of drilling a well and excluded any payments to surface-owners and overhead costs. No credit was given for the cost of completing a well. Credits may be used for any royalty payments to the Alberta government after April 1, 1987 and are transferable. Apparently, some companies sold their credits for 50 cents on the dollar.

EDAP involved a two step process:

1. **Confirmation of Eligibility.** In the same way as under DDAP, companies first applied to reserve incentive funds, using an Approval of Financial Expenditure (AFE) form. The AFE contained information on the location, characteristics and estimated cost of the proposed exploratory well. After verifying that the proposed well met eligibility requirements and that its proposed cost was reasonable, the Department of Energy would reserve the projected royalty credit value against the EDAP obligation and issue the confirmation of eligibility. The company then had 30 days to spud the well before the confirmation expired.

2. **Verification of Eligible Costs.** After drilling its exploration well, a company had six months to submit its application for the royalty credit. All invoices for the cost of drilling the well had to be paid before submitting the application. After reviewing the submitted application, the Department of Energy would issue the royalty credit voucher. Initially, the amount of credit that was to be

allowed by the government equaled 50 percent of the lesser of the actual cost of drilling the well or the cost that had been approved under the Confirmation of Eligibility. However, because the program expired with $85 million of uncommitted royalty credits, the Alberta government subsequently decided to provide credits for 50 percent of the actual cost of drilling a well irrespective of whether the actual costs exceeded the AFE approval costs.

In the case of both the DDAP and EDAP, over half of the qualifying wells were drilled in November and December. Two reasons apparently accounted for the last-minute activity: (1) firms were waiting to see that there would be no further decline in oil prices and (2) warm fall and early winter weather prevented drilling in many areas where the ground was too soft to support drilling equipment. A result of the late activity was a shortage of active rigs in the final months of the year and an inability of some firms to drill approved wells within the eligibility period.

Statements by Alberta Department of Energy officials indicate that some changes would be made if they were to implement these two incentive programs again. In DDAP, cost sharing for drilling would begin with the most shallow wells even if for only a small fraction of cost. Providing credits for the shallower wells would help the smaller companies, which generally do not drill as deeply as the larger companies.

In EDAP, the government would share in completion costs and would allow the option of paying in cash instead of royalty credits. Department officials believe these actions would improve the program's effectiveness in promoting additional exploration activity.

GEOPHYSICAL ASSISTANCE PROGRAM (GAP)

The GAP, which ran from June through December 1986, was intended to support geophysical activity in Alberta. Apparently more than in the case of the EDAP and DDAP, the program was also seen as providing a boost to the financial condition of the Alberta petroleum industry in this case, the geophysical services sector of the industry, which was particularly hard hit by the downturn in activity accompanying low oil prices. The obligated budget was $50 million, with $13 million left at the end of the program.

Under the GAP, companies received cash rebates or royalty credits equal to 35 percent of the cost of seismic reflection programs recorded after June 3, 1986 and before January 1,

1987. To qualify for the cost-sharing, the geophysical evaluation program had to evaluate the subsurface of lands located not more than 1.7 kilometers from lands in which petroleum, natural gas or oil sands were Alberta government owned.

WELL SERVICING ASSISTANCE PROGRAM (WSAP)

The WSAP, which also ran from June through December 1986, provided $50 million in cost-sharing for the labor cost of servicing wells. A principal purpose of this program was to save jobs in the petroleum service industry. WSAP paid 50 percent of the contract labor portion of eligible maintenance, repair and service work on eligible wells. All work had to be completed and paid for before a company could apply for reimbursement. Reimbursement could be as cash or in royalty credits subject to the applying company's preference.

This program was oversubscribed by an estimated $10-25 million: if the program's funding rules were followed precisely, the companies filing claims near the end of the eligibility period would not be reimbursed. However, with remaining funds in EDAP and GAP, it is expected that the government will cover the oversubscription.

CRUDE OIL ROYALTY PROGRAM (CORP)

To encourage additional exploration and development activity, the government of Alberta introduced CORP, which provides a royalty holiday for production from wells drilled or deepened into new conventional oil pools or extensions of current pools. A royalty holiday is an exemption from royalty payments to the crown for a specified length of time. To be eligible for the holiday, the new or deepened well must meet three basic criteria:

- The well must be on crown land.
- The spudding of the well, or the beginning of drilling to deepen an existing well must occur between May 31, 1985 and June 1, 1988
- The drilling spacing unit (DSU) applicable to the zone in which the new or deepened well is completed must be wholly outside the pool boundaries, as defined by the Alberta Energy Resources Conservation Board.

The application for royalty holiday must be received within six months of the completion of the well.

The royalty holiday begins either on the first day of the month in which production begins or an application is received, whichever is later. This permits licensees to select the month of commencement of the royalty holiday. As desired, applications may be filed in a way to exclude the month(s) in which test production occurs and/or to start the royalty holiday at the first month in which full production is expected.

Originally, the Alberta government placed a dollar ceiling per well, with a set limit of $1 million or twelve months, whichever came first. However, in October 1986, the government revised the ceiling as follows. A five-year holiday with no dollar ceiling applies if a company drills before January 31, 1987; if a company drills during the remainder of 1987, it will receive a three-year holiday. Wells drilled during 1988 will receive a one-year holiday.

Sources of information:

Various documents on the Alberta Petroleum Incentives Program, received from the Alberta Department of Energy.
Telephone interviews with:
David Coombs, Manager, Development Drilling
Robert Mitchell, Manager, Royalty Holidays
W.H. Ingram, Wing Consultants, Ltd.

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